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PROJECTION COMPLETION
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COAL GASIFICATION IN SOUTHEASTERN OHIO: WATER SUPPLY AND DEMAND

Elbert E. Whitlatch, Jr.

Assistant Professor
Department of Civil Engineering
The Ohio State University

United States Department
of the Interior

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State of Ohio
Water Resources Center
Ohio State University

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Assistant Professor
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The Ohio State University

WATER RESOURCES CENTER
Engineering Experiment Station
THE OHIO STATE UNIVERSITY
Columbus, Ohio 43210

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ABSTRACT

A review of the need for coal gasification is made at the National level and for the State of Ohio. Current State energy policy promotes the construction of both low and high-Btu coal gasification plants in Ohio. Water requirements of such an industry are estimated and water availability is determined for the Southeastern Ohio study area. Direct stream use, reservoir and groundwater sources are compared economically. Linear programming optimization models are also developed for the coal gasification siting problem. These incorporate the cost of plants, gas transmission, coal supply and transport, solid waste disposal and water supply. Economic efficiency is achieved in meeting the demand for gas at designated market centers. Conclusions are drawn and recommendations made for further analysis.

PROJECT PERSONNEL

Faculty

Name	Project Position	Department
Elbert E. Whitlatch, Jr.	Principal Investigator	Civil Engineering
Keith W. Bedford	Investigator	Civil Engineering

Graduate Students

Name	Project Position	Department
Kristine A. Rebholz	Research Assistant	Civil Engineering

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Chapter 1 - SUMMARY, CONCLUSIONS, AND RECOMMENDATIONS

1.1 Summary

The demand for natural gas in the United States at existing prices exceeds the available supply. Cutbacks have had to be made in most geographical areas for certain types of users. In less than 40 years, the natural gas supply of the United States will likely be entirely used up if current discovery and usage rates are projected into the future. The State of Ohio has already felt the effects of natural gas cutbacks for industrial users, and more severe restrictions on use are projected for the immediate future.

In light of these National and State conditions, Ohio has developed a State energy policy which places the development of a coal conversion industry as a primary objective. Both low and high-Btu coal gasification plants, as well as coal liquefaction facilities, have been promoted at the State level. Simultaneously, the State maintains environmental goals and policies which may be affected if large-scale development of a coal conversion industry were achieved. In particular, the present study examines the likely scale of water consumption by both low and high-Btu coal gasification plants in Ohio, and relates this use to the available supply of water in Southeastern Ohio, that portion of the State projected to be the site of such an industry. Alternative sources of water examined in the study area are: 1) direct stream (low-flow) use, 2) reservoir sources, and 3) groundwater. These are compared in a generalized economic analysis, and conclusions are made as to the most likely sources of water for a coal conversion industry.

Since the severity of environmental impacts depends greatly upon specific site characteristics, an effort is made to develop a planning model that would identify the most likely generalized sites for a coal conversion industry on the basis of economic efficiency. Two alternative mathematical models are formulated and presented for this purpose.

The first can be used to determine the sensitivity of high-Btu coal gasification plant location to changes in unit costs of coal supply and transport, gas transmission, solid waste disposal, or water supply. Similar sensitivity studies can be conducted upon the total quantities of coal and water available, or projected gas demands in different geographical areas. This is important since many times the availability of resources or projected demands are known only within certain limits. The second model takes into account trade-offs involved between construction of low and high-But plants. For instance, the model could be used to test the sensitivity of high-Btu plant locations to changes in service demand caused by alternative patterns of low-But plant construction for industry, or to any other change in problem parameters, such as cost coefficients, total consumer demand or water availability. Both models allow planning for water supply by showing the true economic value of water when used in the coal gasification industry.

1.2 Conclusions

The major conclusions of the present study are listed as follows:

1. In 1973, Ohio ranked fifth highest in both gas consumption and in total energy use as compared to other states. Compared to National averages, the proportion of current Ohio gas consumption in interruptible industrial service is very low (at 3.8 percent). Use of gas for utility power generation is also very small. With such a distribution of use, large cutbacks in gas supplies would be expected to affect the firm industrial category in Ohio more heavily than would be the case for the United States as a whole.
2. Primary Iron and Steel, Stone, Clay, Glass and Concrete Products, and Chemical and Allied Products are the largest users of industrial gas in Ohio. These industries are the most likely, therefore, to suffer in any industrial gas cutback.
3. In 1973, Ohio produced only 8.5 percent of the State's gas consumption from its own gas wells. This situation is not expected to change greatly in the near future, despite increased levels of domestic drilling in the last 10 years. The State is therefore heavily dependent upon the interstate gas market.
4. A State energy policy has developed slowly over the past three

years (1972 to present). Low and high-Btu coal gasification occupies a foremost place in this policy. A new State entity, the Energy and Resource Development Agency, was created in August, 1975 and has comprehensive powers to plan energy development in the State. The Agency's enabling legislation requires that it give priority to the establishment, location and construction of one low-Btu and one high-Btu coal conversion plant in the State. Therefore, coal gasification plant construction is given high priority at the State level, and it is likely that such construction will be initiated in the State of Ohio within the very near future.

5. The State is committed to a high level of environmental quality. Energy development must therefore occur in such a way so as to not compromise this goal. The environmental effects of coal conversion facilities, particularly high-Btu coal gasification plants, are not well known, however. Research is now being conducted at the National level with respect to these impacts, but such studies have not been widely interpreted.

6. Water conservation has not been a prime consideration in coal gasification plant design for the vast majority of currently proposed processes. Estimates of water use are absent in many, if not most, process descriptions in the literature. However, from available literature, the range of consumptive water use in a 250 million cubic feet per day, high-Btu plant, is from 7 to 45 million gallons per day (MGD). The most likely consumptive water use for such a plant in Southeastern Ohio is 25 MGD.

7. The relative availability of water at a potential coal gasification plant may significantly affect the final price of gas. For Southeastern Ohio, each 10 cents per 1000 gallons increase in the price of water would cause a gas cost increase of 1.007 cents per 1000 cubic feet.

8. The direct use of stream sources is generally not possible in the study area due to periodic low-flows less than the 25 MGD consumptive

use. Parts of the Muskingum River and sites along the Ohio River are the only feasible sites in this regard.

9. Stream segments which could support a 25 MGD yield through construction of average-size reservoirs (for the study area) are abundant in Southeastern Ohio.

10. Based upon a required yield of 25 MGD to serve a coal gasification plant of standard size, few geographical regions in the study area would have sufficiently high groundwater yields to provide a dependable and economical source. Nevertheless, these areas are distributed along stream valleys in such a manner as to represent potential alternative sources to surface water supplies.

11. A generalized cost analysis of three alternative water supply sources indicates that a direct stream source would very likely be the least expensive alternative, followed by reservoir and groundwater sources. The respective costs of these were calculated to be 17.9, 25.4, and 27.2 cents per 1000 gallons. These costs do not include the cost of neutralizing surface waters if acid mine drainage is present. In such a case groundwater would very likely be the most economical source.

12. For a variety of reasons, the conjunctive use of ground and surface waters should be considered in any water supply plan for a coal gasification complex.

13. At a gas price of $1.50 per 1000 cubic feet, the cost of water would generally represent from 1.2 to 1.8 percent of the final gas price. This is not an insignificant portion of total costs.

14. Mathematical models of the energy facility siting process can be developed and would be useful in the comparison of alternative sites and gas production modes. For example, the trade-offs between low-Btu and high-Btu coal gasification plant construction could be usefully examined.

1.3 Recommendations

The following recommendations for further study are made:

1. In view of the general lack of reliable estimates of water consumption at coal conversion facilities, it is recommended that the Federal government support a detailed study of water use and conservation in both the Lurgi and advanced technology processes. Such a report should provide enough supportive analysis to permit independent review and corroboration of findings. This should be done for both low and high-Btu processes.
2. Site-specific reconnaissance should be carried out in the selected study area for both reservoir sites and potential groundwater aquifers capable of supplying a coal conversion industry. This could be conducted along the lines of a similar study completed and published by the State of Illinois (Smith and Stall, 1975).
3. The coal gasification siting models developed in this report should be applied to the study area or to an enlarged geographical area including Southeastern Ohio. These would yield valuable information concerning problem parameters and would indicate the relative value of low versus high-Btu coal gasification plants.

Chapter 2 - NEED FOR COAL GASIFICATION

2.1 National Gas Supply and Demand

The demand for natural gas in the United States at existing prices exceeds the available supply. Cutbacks have had to be made in most geographical areas for certain types of users. Projections of gas supply and demand in the United States have been made by the National Petroleum Council (1972) and are shown in Table 2-1. These indicate a shortage of 2.69 trillion cubic feet (TCF) for the year 1975, or 10.9 percent of the projected requirements for that year. In 1980 and 1985 shortfalls of 18.8 and 21.0 percent are projected, respectively. Imports of natural and liquified natural gas (LNG) from Canada and Alaska, respectively, will be heavily depended upon to compensate for a projected decrease in domestic (lower 48 states) production.

Proved reserves of natural gas are those reserves which have been verified by actual drill logs and records. At the 1972 rates of usage for various United States energy fuels, the time necessary to deplete these supplies can be computed as in Table 2-2. As shown, the time needed to deplete United States proved gas reserves is only 11 years. The same figure for oil is only 8 years, while proved coal supplies could last for 823 years at the 1972 usage rate. Proved gas reserves grew from 147 TCF in 1945 to a peak of 293 TCF in 1967. Since that time proved reserves have declined and were 250 TCF in 1973, reflecting a rate of usage 2 to 3 times greater than the rate of finding in the Continental United States (Federal Energy Administration, 1974). If past discovery patterns continue into the future, the natural gas supply of the United States could last for 40 years at present consumption rates. Since the potential demand for natural gas has been increasing steadily in the recent past, however, the time to depletion would be less than 40 years.

Actual natural gas production for the years 1947 to 1973 is shown in Figure 2.1 along with proved reserves. An increase in production is evident for every year up to 1970. Since that year, however, production has leveled off to a rate of approximately 22.5 TCF/year for both 1971 and 1972 and actually <u>declined</u> in 1973 to a level of 21.3 TCF (Federal Energy Administration, 1974).

Gas supply	1971	1975	1980	1985
Conventional domestic	19.97	20.17	17.60	16.11
Alaska North Slope	0	0	1.00	2.00
Canadian imports	0.90	1.00	1.60	2.70
Mexican imports	0.05	0.05	0	0
Total natural	20.92	21.22	20.20	20.81
LNG imports	0	0.24	2.28	4.11
Coal gasification	0	0	0.36	1.31
Liquid gasification	0	0.64	1.32	1.32
Total Syngas	0	0.64	1.68	2.63
Nuclear stimulation	0	0	0.09	0.73
Grand total, supply	20.92	22.10	24.25	28.28
Requirements	19.64	24.79	29.88	35.78
(Shortage) or surplus	1.28	(2.69)	(5.63)	(7.50)

Figures include gas from South Alaska.

Table 2-1. United States Supply and Demand for Natural Gas (after National Petroleum Council, 1972, trillion cubic feet).

Source	Fuel Units	Quadrillion BTU's	Years left at 1972 Consumption Levels
Coal			
high sulfur (more than 1%)	273 billion tons	6908	
low sulfur (less than 1%)	160 billion tons	3838	
TOTAL	433 billion tons	10,746	823
Oil			
lower 48 (crude)	30 billion barrels	176	
natural gas liquids	6 billion barrels	37	
Alaska	10 billion barrels	59	
TOTAL	46 billion barrels	272	8
Gas			
lower 48	218 TCF	225	
Alaska	32 TCF	32	
TOTAL	250 TCF	257	11
Shale	20-170 billion barrels	116-986	3-28
Tar Sands	29 billion barrels	168	28

Table 2-2. Proved Fuel Reserves (Federal Energy Administration, 1972).

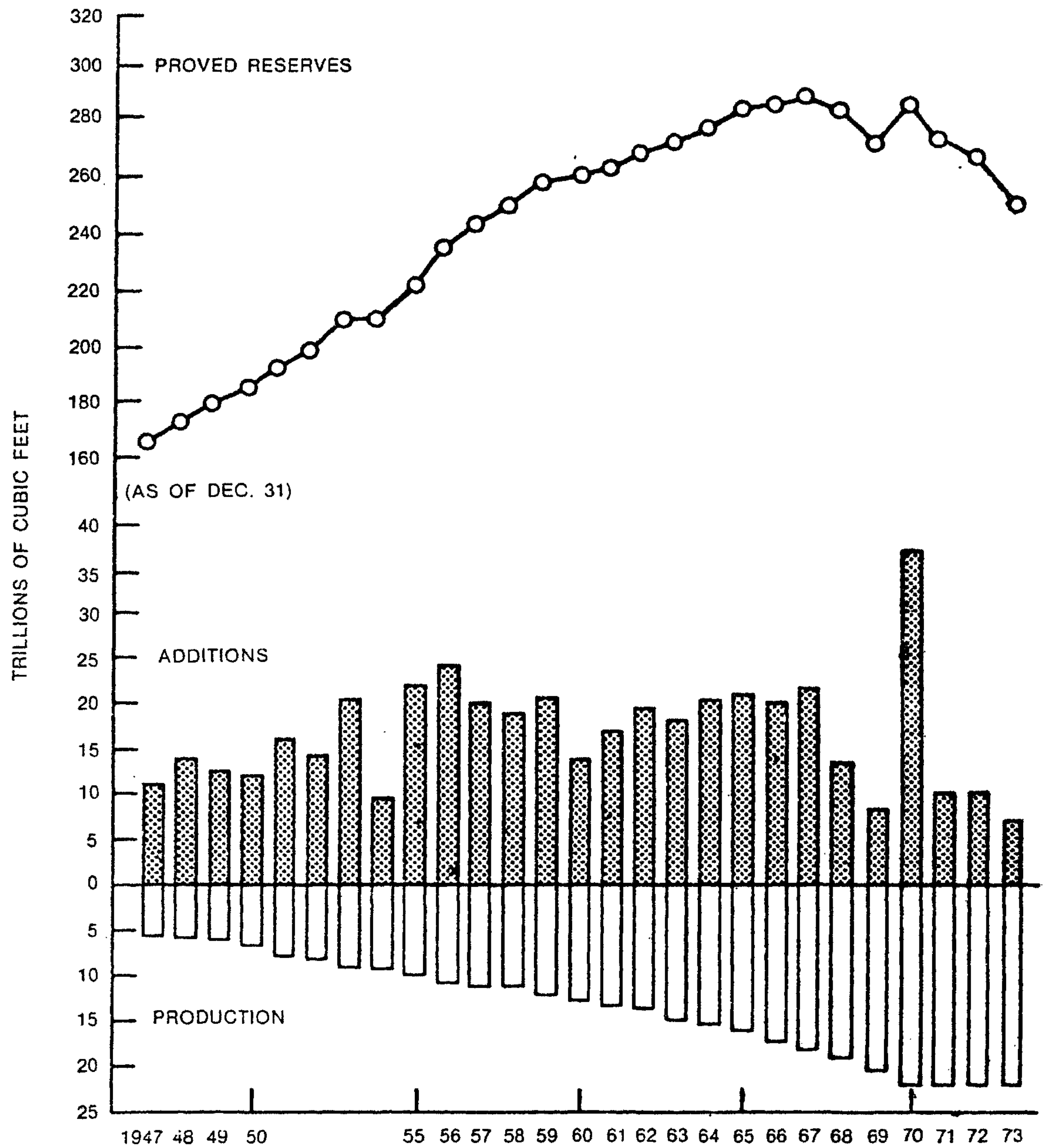

Figure 2.1 United States Natural Gas Reserves and Production (Federal Energy Administration, 1974).

To a large degree the shortfall in supply of gas has been caused by an artificially low price for gas at the wellhead. In 1972 the average wellhead price was 18.6 cents per thousand cubic feet (¢/MCF) of gas, reflecting the regulated status of both old and new gas wells. By contrast, imported liquified natural gas from Algeria was selling at about $1.50/MCF. In making forecasts of future production levels of any energy source, therefore, the price of each must be carefully considered. A recent forecast of the composition of future United States energy consumption was made by the Federal Energy Administration (1974) under various pricing assumptions for oil and gas. Table 2.3 shows forecasts of the future production of four principal energy sources in the United States under the alternative assumptions that foreign oil would cost $7 and $11 per barrel. (The January, 1974 price of world oil was $11 per barrel as a consequence of actions taken by the Organization of Petroleum Exporting Countries (OPEC)). It was also assumed that gas prices would be deregulated and allowed to rise to $1.00/MCF at the city gate. It is noteworthy that under the two alternative prices for oil, domestic United States production of gas does not change greatly. If gas remained at a regulated level of $0.42/MCF, however, 1985 gas production would fall to 15.2 TCF from the projected level of 23.9 TCF when oil is priced at $7 per barrel. Also, since domestic gas reserves are expected to decline under either price assumption, natural gas production will show an annual decrease beyond 1985.

From the same Table it can be seen that both coal and nuclear sources of energy are expected to assume a very much larger share of the total energy supply while oil and gas decrease in importance.

<u>Industry plans for gas delivery</u>. A recent survey of the gas industry was made by the Future Requirements Committee, University of Denver Research Institute, Denver, Colorado.[1] The intent of the survey was to determine the proportion

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[1] The work was sponsored by the American Gas Association, the American Petroleum Institute, and the Independent Natural Gas Association of America.

				Percent Share of Market		
	1972	1985 at $7 per barrel	1985 at $11 per barrel	1972	1985 at $7 per barrel	1985 at $11 per barrel
Oil	22.4	23.1	31.3	37.1	27.4	32.5
Gas	22.1	23.9	24.6	36.5	28.3	25.5
Coal	12.5	19.9	22.9	20.6	23.6	23.7
Nuclear	0.6	12.5	12.5	1.0	14.8	13.0
Other	2.9	4.9	5.1	4.8	5.9	5.3
TOTAL PRODUCTION	60.4	84.3	96.4	100.0	100.0	100.0

Table 2.3 Composition of United States Domestic Energy Production, 1985, (after Federal Energy Administration, 1974, quadrillion Btu's).

of market requirements that individual companies actually plan on meeting from 1973 through 1980, based upon their realistic expectations of supplemental and natural gas supplies from all sources. Data in Table 2.4 are based on this survey.

The overall compound rate of growth in consumption is seen to be 1.2 percent from 1972 to 1980. This compares to an estimated 5.0 percent increase in gas requirements for the same period. In 1980, therefore, only 74 percent of the gas requirement is planned to be met by the industry.

Rates of increase in consumption by user class are not uniform. Almost all utilities indicated that residential and commercial demands for gas would be given priority over firm industrial and interruptible service for both industrial and electric power classes. Cutbacks in the latter category are anticipated to be particularly strong, with use actually decreasing at an 8.1 percent rate over the eight years.

The overall shares of gas consumption for the residential and commercial sectors in 1980 are projected to increase relative to their shares in 1972, generally at the expense of interruptible service to electric power and industry.

Since the above projections were made, supplemental data for the year 1973 have become available (Future Requirements Committee, 1974). These indicate that even the above company projections have been optimistic as to available supply. Actual gas consumption by user class for 1973 is shown in Table 2-5. Total consumption excluding field use was 21,327 billion cubic feet. This is 1,085 billion cubic feet, or 4.8 percent, below the comparable 1972 figure. Warmer-than-usual weather in most of the nation had some influence on this total, but gas curtailments were also a major factor. Actual consumption was only 95.3 percent of industry-estimated for the year. Both firm residential and industrial use declined slightly, but major decreases were recorded in utility power generation, both firm and interruptible. Inter-

Classification	1972 Actual Bcf	1972 Actual Percent of Total	1980 Estimated Bcf	1980 Estimated Percent of Total	Increase Bcf	Increase Percent	Increase Compound Growth Rate - %
Residential	5,277	23	6,471	26	1,194	23	2.6
Commercial	2,239	10	3,065	12	826	37	4.0
Industrial	6,257	28	6,846	28	589	9	1.1
Electric Power							
Firm	2,444	11	2,773	11	329	13	1.6
Interruptible	1,828	8	981	4	(847)	(46)	(8.1)
Interruptible Industrial	2,884	13	2,938	12	54	2	0.2
Other	1,698	7	1,754	7	56	3	0.4
TOTAL	22,627	100	24,828	100	2,201	10	1.2

Table 2-4. United States Gas Consumption by Class of Service, 1972 and 1980 (Source: Future Requirements Committee, 1973).

	Volumes			1973 Actual Volumes Compared to 1972 Actual Volumes	
	1972 (Actual)	1973 (Actual)	1973 (Est.)	Difference Decrease ( )	%
Firm	13,669	13,447	14,117	(222)	-1.6
Residential	5,173	4,983	5,300	(190)	-3.7
Commercial	2,239	2,248	2,334	9	+0.4
Industrial	6,257	6,216	6,483	(41)	-0.7
Utility Power Generation	4,161	3,651	3,773	(510)	-12.3
Firm	2,333	2,104	2,243	(229)	-9.8
Interruptible	1,828	1,547	1,530	(281)	-15.4
Interruptible Industrial[1]	2,884	2,778	2,868	(106)	-3.7
Other, Including Region 11 Total[2]	1,698	1,451	1,628	(247)	-14.6
Total Consumption Excluding Field Use	22,412	21,327	22,386	(1,085)	-4.8
Field Use	1,907	1,964	1,907	57	+3.0
Total Consumption Including Field Use	24,319	23,291	24,293	(1,028)	-4.2

[1] Other than utility power generation.

[2] Region 11 included with "Other" since data by class of service not available for this region.

Table 2-5. United States Gas Consumption by Class of Service, 1972 and 1973 (billions of cubic feet; source: Future Requirements Committee, 1974).

ruptible industrial use declined 3.7 percent. Overall, these data would seem to reflect an over-optimism on the part of the industry in its original consumption estimates, at least for the year 1973.

In summary, the supply of natural gas at the National level is not adequate to meet projected gas demands at current prices. For deregulated prices the situation is not significantly better, and shortfalls in supplies beginning in 1973 will undoubtedly continue and likely increase in relative severity throughout the coming decade.

2.2 Ohio Gas Supply and Demand

Ohio ranks as one of the top states in the nation with respect to gas and total energy consumption. Table 2-6 shows Ohio ranking fifth in gas consumption for 1973. On a total energy consumption basis, Ohio's rank was also fifth for 1971 data (Frank and Weber, 1973). The data also indicates the relative importance of the East North Central and West North Central regions of the United States for gas consumption, in addition to the principal gas producing states of Texas and Louisiana.

State and Rank	Gas Consumption (million CF)	State and Rank	Gas Consumption (million CF)
1. Texas	4,014,479	11. Indiana	539,014
2. California	2,087,972	12. Arkansas	404,437
3. Louisiana	1,804,374	13. Missouri	404,056
4. Illinois	1,143,241	14. Wisconsin	376,033
5. Ohio	1,102,495	15. Iowa	364,159
6. Michigan	936,747	16. Georgia	363,945
7. Pennsylvania	830,275	17. Minnesota	354,210
8. New York	722,651	18. New Jersey	325,414
9. Kansas	570,951	19. Florida	312,170
10. Oklahoma	556,622	20. Tennessee	311,648

Table 2-6. Gas Consumption for Top 20 States, 1973 (Source: Future Requirements Committee, 1974).

The distribution of gas consumption among user classes is important when considering both conservation measures and substitute fuel sources. Table 2-7 indicates this distribution for Ohio and surrounding states, as well as for selected major consumption states. Compared to the national average, Ohio has much larger proportions of its gas consumption in firm service to residential, commercial, and industrial users. By contrast, Ohio's proportional gas consumption in interruptible industrial service is only 3.8 percent. Use of gas for utility power generation is also very small, with 0.5 and 0.1 percent of total consumption represented in the firm and interruptible categories, respectively, compared to national averages of 9.9 and 7.3 percent. With such a distribution of use, large cutbacks in gas supplies would be expected to affect the firm industrial category in Ohio more heavily than would be the case for the United States as a whole. For states surrounding Ohio the situation is very much the same, except that the proportional uses of interruptible industrial gas in Michigan and Kentucky approximate the national average. Cutbacks in this category could serve to insulate firm industrial gas consumption in the short-run for these two states. Overall, however, larger cutbacks in gas supplies in Ohio and surrounding states are likely to have a profound impact on firm industrial service.

By contrast, use of gas in the producing states of Texas and Louisiana is heavily concentrated in the lower priority area of firm and interruptible utility power generation. California, the second largest gas consuming state, has a high usage of both interruptible industrial and interruptible utility power generation. Cutbacks in such states could therefore be made without greatly affecting firm industrial uses.

Industrial gas consumption for the ten-state statistical region[2] including Ohio is broken down by Standard Industrial Classification (SIC) in Table 2-8. Primary

[2] The Appalachian Region designated by the Future Requirements Committee (1974) is comprised of Delaware, District of Columbia, Kentucky, Maryland, New Jersey, New York, Ohio, Pennsylvania, Virginia and West Virginia.

State and Rank	Firm			Interruptible Industrial	Utility Power Generation		Other	Total*	
	Residential	Commercial	Industrial		Firm	Interruptible		Percent	Million CF
National Average	23.4	10.5	29.1	13.0	9.9	7.3	6.8	100.0	21,327,272
5. Ohio	40.2	16.7	35.9	3.8	0.5	0.1	2.8	100.0	1,102,495
4. Illinois	39.1	18.2	28.8	4.3	2.9	0.4	6.3	100.0	1,143,241
6. Michigan	37.2	19.8	25.4	12.6	1.4	0.3	3.3	100.0	936,747
7. Pennsylvania	35.7	13.5	38.6	6.6	0.2	0.2	5.2	100.0	830,275
11. Indiana	28.7	14.0	45.4	6.9	1.8	0.1	3.1	100.0	539,014
24. Kentucky	29.3	13.7	21.0	12.9	0.1	2.9	20.1	100.0	271,321
27. W. Virginia	26.8	12.1	35.6	0.7	0.0	0.0	24.8	100.0	207,840
1. Texas	6.1	3.5	48.0	5.9	23.7	6.0	6.8	100.0	4,014,479
2. California	31.3	9.7	4.8	28.8	0.5	21.7	3.2	100.0	2,087,972
3. Louisiana	6.5	1.3	60.0	2.0	20.9	3.9	5.4	100.0	1,804,374

* Total gas consumption excluding field use.

Table 2-7. Distribution of Gas Consumption Among User Classes, Ohio and Selected States, 1973 (percent; source: Future Requirements Committee, 1974).

SIC Description	Percentage of Use		Total Use (Million CF)	Percentage of Total Industrial Use
	Firm	Inter-ruptible		
MANUFACTURING:				
Primary Iron and Steel	87.0	13.0	284,376	21.5
Stone, Clay, Glass and Concrete Products	84.3	15.7	172,161	13.0
Chemicals and Allied Products	76.5	23.5	121,736	9.2
Petroleum and Miscellaneous Coal Products	90.5	9.5	76,605	5.8
Primary Non-Ferrous Metals	84.1	15.9	63,374	4.8
Fabricated Metal Products	92.1	7.9	62,662	4.8
Food and Kindred Products	56.1	43.9	48,099	3.6
Electric and Electronic Equipment	81.9	18.1	35,569	2.7
Transportation and Equip.	94.6	5.4	30,013	2.3
Paper and Allied Products	72.1	27.9	29,219	2.2
All Other Manufacturing	85.1	14.9	107,711	8.2
OTHER SIC CLASSES	44.6	55.4	1,578	0.1
TOTAL INDUSTRIAL REPORTED	83.6	16.4	1,033,103	78.2
NOT CLASSIFIED OR UNREPORTED	61.8	38.2	287,502	21.8
TOTAL	78.9	21.1	1,320,605	100.0

Table 2-8. Industrial Gas Consumption in the Appalachian Region by Standard Industrial Classification, 1973 (after Future Requirements Committee, 1974).

Iron and Steel is the largest consumer of industrial gas, followed by Stone, Clay, Glass and Concrete Products; and Chemicals and Allied Products. These are also the main industrial gas consumer categories in Ohio.

Ohio gas consumption can be traced from 1966 to 1973 as in Table 2-9. Estimated annual consumption from 1973 to 1980 as found by the Future Requirements Committee (1973) is also given. Actual consumption has grown slowly at an annual compound rate of 1.7 percent, with decreases in consumption recorded in the years 1970 and 1973. Gas industry estimates of 1973 Ohio gas consumption, made very early in that year, prove to be high compared to actually recorded use. Warmer-than-normal temperatures for the year are given as the main cause for the lower consumptive use. A national conservation drive affected only the last two months of that year. Consumption projections for 1973-1980 (as made by utilities serving the area) show a 0.9 percent annual rate of increase. This is about one-half the historical rate, and reflects anticipated supply shortages.

A detailed examination by user class for the above projection indicates that firm residential, commercial and industrial gas usages are expected to increase at an approximately identical annual compound rate of 1.3 percent. Interruptible industrial and firm utility power generation, however, are expected to rapidly decline at annual compound rates of 3.0 and 12.0 percent, respectively. Interruptible utility power generation, representing a very small total usage, is expected to increase at a 4.0 percent rate. In general, therefore, these projections reflect the gas industry's national trend of decreasing interruptible industrial usages and phasing out supplies for utility power generation.

Finally, industry estimated consumption trends can be compared to estimated future gas requirements in Ohio. These are shown in Table 2-10. Gas requirements were estimated by utility respondents on the basis of no anticipated supply shortage, prevailing gas prices, economic conditions, and local market trends. The estimated 1980 gas requirement represents a 4.0 percent annual rate of increase from 1972, compared to 0.9 percent for estimated consumption. In 1980, about 76 percent of

Year	Actual Gas Consumption (million CF)	Percent Change from Previous Year	Year	Estimated Gas Consumption (million CF)	Percent Change from Previous Year
1966	980,453	---	1973	1,185,503	-1.6
1967	994,136	1.4	1974	1,193,108	0.6
1968	1,060,007	6.6	1975	1,195,461	0.2
1969	1,126,197	6.2	1976	1,203,211	0.6
1970	1,112,759	-1.2	1977	1,232,630	2.4
1971	1,174,458	5.5	1978	1,257,300	2.0
1972	1,204,847	2.6	1979	1,276,891	1.6
1973	1,102,495	-8.5	1980	1,296,711	1.6

Table 2-9. Ohio Actual and Estimated Gas Consumption, 1966-1980 (after Future Requirements Committee, 1973, 1974).

Year	Estimated Consumption (million CF)	Estimated Requirement (million CF)	Shortfall (million CF)	Consumption as Percent of Requirement
1972*	1,204,847	---	---	---
1975	1,195,461	1,420,611	225,150	84.2
1980	1,296,711	1,710,567	413,856	75.8
1985	---	2,026,280	---	---
1990	---	2,417,919	---	---
1995	---	2,904,738	---	---

* Actual usage for 1972.

Table 2-10. Estimated Gas Consumption and Requirement for Ohio (Source: Future Requirements Committee, 1973).

estimated requirements are projected to be met.

On a seasonal basis, the supply situation is more severe. Columbia Gas Distribution Company, the main retailer of gas in Ohio, has predicted a 65 percent curtailment of natural gas supplies to industry for the winter season 1975-1976, and by 1980 "likely no gas at all" (Schott, 1975). The Columbus, Ohio, school system will be placed under a 26 percent reduction in gas supplies for the period November 1, 1975, to March 31, 1976, if the weather is severe for that period (Brooks, 1975).

A Federal Energy Administration report issued in late August, 1975, however, indicates that curtailments to Ohio industries for the winter season will not be as high as predicted by an earlier congressional committee (at 55 percent cutback) or Columbia Gas. Their report predicts only a 10 percent reduction of firm industrial use of gas (Columbus Citizen-Journal, 1975). But even this level of reduction will have a significant effect upon such industries as primary metal, stone, clay, and glass, where natural gas is used directly in the manufacturing process.

On the supply side, Ohio does produce some oil and gas domestically. Production figures for 1964-1973 are shown in Table 2-11. Contrary to national trends, Ohio's gas production has increased steadily since 1968 to a level of 94,121 MMCF in 1973. The quantity of gas reserves has also increased, due largely to renewed activity in gas well drilling since 1968. Most gas production and new drilling activity occurs in Tuscarawas, Muskingum, Noble, Holmes, Trumbull, Guernsey, Stork and Mahoning counties, in decreasing order of new drilling activity. These lie in East-Central and Northeastern Ohio. Silurian "Clinton" Medina sandstone and the lower Mississippian Berea sandstone were the target of most new wells. The average price paid for gas was 42.27¢/MCF, and increase of 2.87¢/MCF over the previous year (Division of Mines, 1973).

The 1973 Ohio gas production figure of 94,121 MMCF represents only 8.5 percent of the State's consumption for the same year. Clearly, even with greatly increased activity in domestic production, Ohio will remain dependent upon national gas supplies for the great majority of her needs.

Year	Number of New Gas Wells	Gas Production (million CF)	Gas Reserves (million CF)
1964	202	37,713	318,096
1965	195	40,123	326,603
1966	162	43,568	333,645
1967	189	42,500	339,995
1968	145	42,673	351,222
1969	257	49,793	392,379
1970	517	73,759	557,455
1971	542	82,678	615,477
1972	588	90,487	715,151
1973	759	94,121	808,641

Table 2-11. Ohio Gas Production and New Well Completions (Source: Division of Mines, 1973).

2.3 Ohio Energy Policy

State energy policy has developed slowly over a period of about three years, 1972 to present. First planning efforts evolved from the Governor's Business and Employment Council, established on May 23, 1972. This group recognized the importance of natural gas supplies to Ohio's industrial well-being, and promoted the development of studies related to the conversion of coal into low-Btu gas at industrial sites. An industrial consortium was suggested as the appropriate vehicle for gasifier design, construction, and operation, with matching funds to be sought from the Federal Office of Coal Research. The Council also recommended the creation of the Ohio Development Center as a state-funded organization charged with the on-going promotion of seed research and development projects in such nationally important areas as energy, environment, transportation and health care. The intention was to attract continued Federal support for such projects in Ohio, thereby benefitting the state's economy. The Ohio Development Center was, in fact, established on July 27, 1974.

Meanwhile, gasoline and other fuel shortages in Ohio initiated the creation of the Governor's Task Force on Energy in October, 1973, along with legislative action creating the Energy Emergency Commission on April 22, 1974. The five-member Commission was charged with collecting data and making projections concerning the supply and use of energy in Ohio; preparing energy emergency contingency plans to prevent or ameliorate the impact of energy shortages; determining when an energy emergency exists; and cooperating with the Federal government on energy matters (Ohio General Assembly, 1974). An eighteen-member Energy Advisory Council was also established to advise the Commission on possible impacts of Commission emergency plans on important industrial and public interest groups, as well as advising the Commission about current State agency policies. The first meeting of the Council occurred on September 25, 1974.

The State has consistently supported the location of a coal conversion plant within Ohio, and several specific sites and types of plants have been suggested. In September, 1974, the director of the State Office of Community and Economic Development came out in support of an $84 million coal liquefaction plant proposed by Sohio

Oil Company for the Toledo, Ohio area. Support was also given to the plan of Governor Rhodes for a high-Btu coal gasification plant in Belmont County, southeastern Ohio. A contract for $237.2 million has been let by the Federal Office of Coal Research for the ultimate construction of a $400 million high-Btu coal gasification and liquefaction plant. Belmont County, Ohio, was a prime contender along with Wood County, West Virginia, for the plant's location (Roberts, 1975b). Coalcon, an affiliate of Union Carbide and Chemico, is the contractor. Coalcon also considered possible sites in Jefferson, Monroe, and Scioto County in Ohio, but the final decision was to locate the plant at a site near New Athens, Illinois. The decision was based to a considerable extent upon environmental and socio-economic grounds. The Illinois site had been previously strip-mined and is adjacent to the Kaskaskia River in one of the state's highest coal producing counties. Other demonstration plants are to be Federally financed, however, and Ohio will continue in its attempts to attract one or more of these.

In regard to low-Btu coal gasification, the Ohio Development Center has continued and amplified the original proposals of the Governor's Business and Employment Council. The Center, in cooperation with Republic Steel Corporation and CNG Energy Company, initiated a $350,000. study of coal gasification for the steel industry. Studies of potential locations for low-Btu gasification plants are also underway, with Cleveland a prime contender, followed by Youngstown-Warren, Canton, Toledo, Middletown and Dayton. The plants are estimated to cost about $80 million each. In May, 1975, a one-day conference was sponsored by the Center on the topic "Industrial Utilization of Gas from Ohio Coal" at Battelle Memorial Institute, Columbus. Industry was urged to examine its ability to adapt its operations to low-Btu gas.

Most recently, legislative initiatives have resulted in a landmark energy bill being passed and signed into law on August 26, 1975 (Ohio General Assembly, 1975) The measure establishes the Ohio Energy and Resource Development Agency (ERDA) as a new state entity to replace the Ohio Development Center and the Ohio Energy Emergency Commission. ERDA has a nine-member commission and is empowered to construct power plants; coal gasification or fuel refineries; issue revenue bonds for such facilities; assume the functions of the Ohio Energy Emergency Commission and the Ohio Development Center; purchase property, and extend tax incentives to attract a federally funded coal gasification demonstration plant in Ohio. Enabling legislation also requires that the agency give priority to the establishment, location and construction of one low-Btu and one high-Btu coal conversion plant in the State. ERDA thus assumes the primary responsibility for energy planning in Ohio. Other State agencies involved in energy negotiations are the Power Siting Commission, the Public Utilities Commission, Department of Natural Resources, and the Department of Community and Economic Development.

Coal conversion to both low and high-Btu gas has thus assumed primary importance at the State level. Other proposals have been made, however, to increase the supply of natural gas or to decrease its use. Partial price-decontrol on gas during winter emergency periods has been proposed by the Governor as well as by one United States senator from Ohio. This would allow states with shortages to purchase some gas supplies from producer states. Development funds for research and exploratory drilling for shale gas in Appalachia have also been promoted at the gubernatorial level, as well as changes in Federal Power Commission rules prohibiting intra-state transport of local gas in interstate pipelines. Economic incentives are also being provided to local companies if they drill for their own gas supplies in Ohio.

Columbia Gas Distribution Company is privately promoting the construction of a pipeline from Alaska's Prudhoe Bay through Canada to the Mideast and eastern United States. Ohio would reportedly receive 55 to 60 percent of the gas carried in such a pipeline (Roberts, 1975a). The same company has already constructed a liquid hydrocarbon reforming plant at Green Springs, Ohio, to produce a high-Btu gas from a propane-naptha feedstock. The plant has a 250 MMCF/day capacity but is being operated at a level of only 144 MMCF/day due to limited availability of feedstock supplies. A 1974 production cost of about $2 per thousand cubic feet is very expensive, with 85 percent of this cost attributable to feedstock prices.

Finally, Ohio energy policy must be viewed in relation to other State policies. In particular, the State is committed to a high level of environmental quality. Energy development must therefore occur in a way so as to not compromise this goal (Mattox, 1974, p. 3).

Chapter 3 - WATER REQUIREMENTS FOR COAL GASIFICATION

3.1 Introduction

Water conservation has not been a prime consideration in coal gasification plant design for the vast majority of currently proposed processes. Indeed, estimates of water use are actually absent in many, if not most, process descriptions in the literature. A determination of water use is made more difficult by the preliminary nature of most process proposals. A high-Btu (900-1000 Btu/standard cubic foot, SCF) coal gasification plant has not yet been constructed for commercial use anywhere in the world. Most pilot plants serve to test only portions of a process design, making estimates of full-scale plant performance rather unreliable. More experience is available for low (150-250 Btu/SCF) and intermediate (300-500 Btu/SCF)-Btu processes, although much of this is for foreign plant installations.

A review will be given below of the general process steps in coal gasification in order to illustrate points at which water is necessary. Since both process and cooling water is needed, these will be separately discussed. Literature values for predicted water use will be given and conclusions will be drawn as to the range of water use to be expected. Finally, a distinction will be made between water use as indicated by literature estimates and that use which might result for the industry in response to water scarcity, as reflected in price increases (water demand).

3.2 Coal Gasification

That a combustible gas (coal gas at about 500 Btu/SCF) could be produced from coal by heating in a chemical retort (in the absence of air) was discovered in 1670. It was not until 1792, however, that such a gas was used to provide lighting for homes in Scotland. An industry developed and moved into the heating market when Bunsen developed the atmospheric gas burner in 1855. Water gas ("town gas") was also manufactured by reacting hot coke or coal char with steam to produce a mixture of carbon monoxide and hydrogen. The gas had a heating value of about 300 Btu/SCF and had to be enriched through the addition of light fuel gases (methane and propane) obtained through cracking oil at high temperatures (Federal Power Commission, 1973, Perry, 1974).

Some modifications to this process were forthcoming, but it was not until after 1920 that significant improvements were made. In the ensuing years many innovations occurred and are now a part of current coal gasification technology. Since Europe has been more dependent than the United States upon coal as a fuel source, and as a source of many chemicals, most of these advances have occurred overseas.

Commercially proven processes exist for low and intermediate-Btu gas production. Low-Btu gas (producer gas) is suitable for industrial use as a boiler fuel or for use in the generation of electricity. It is made in essentially the same way as water gas, by blasting a hot bed of coal or coke with air or a mixture of steam and air. The product contains a great deal of nitrogen from the air and is therefore low in heat content. Intermediate-Btu gas can be used directly as a boiler fuel, to generate electricity, or as the basic raw material for the production of chemicals or liquid and gaseous fuels. Generally, oxygen must be substituted for air when blasting hot coal or coke as in the production of low-Btu gas. A combination of products of coal devolatilization and steam-oxygen coal gasification produces an intermediate-Btu gas. High-Btu gas, meanwhile, is designed for use as a natural gas substitute (synthetic pipeline gas), and has all of the same uses as natural gas. Intermediate-Btu gas is upgraded to high-Btu gas by further processing.

Coal gasification (and liquefaction) is today seen as a very promising supplemental source of producer and pipeline gas (and oil) in the United States for the period 1980-2000. Before 1980, large-scale (250 million SCF/day) coal gasification plants could not be constructed, and after about the year 2000 other sources of energy such as solar, nuclear, and thermal fusion are expected to be relied upon. Coal is seen as a recommended source of energy for the United States due to its abundance (proven reserves enough to last for about 800 years at current usage rates) and relative inexpense. In addition, Eastern and Midwestern coals are generally found near industrial and population centers, while other (Western and Northern Plains) coal supplies are near railroad and pipeline right-of-ways. Whether an intensive use of coal develops will depend largely upon future economics and technological safety and health considerations in the deep-mining of coal, and environmental considerations relative to strip-mining.

A possible chain of events for the substitution of coal for natural gas and oil supplies would be to 1) convert oil and gas-fired industrial and electricity boilers to the use of coal (where possible), thereby releasing natural gas and oil for other uses, 2) install low and intermediate-Btu gasifiers near large industrial plants for conversion of industrial boilers and furnaces, 3) site and construct high-Btu coal gasification and liquefaction plants. It may be possible to implement the first two options in less than six years, while the latter can only be a long-run (10-20 year) source of relief. Several reviews of the general status of coal gasification and of its future prospects are given in the literature (e.g., see Connor, 1974, Osborn, 1974, Perry, 1974, Squires, 1974, and Williams and Dressel, 1973).

3.2.1 Steps in coal gasification

Conversion of coal to a high-Btu, synthetic natural gas (SNG) product involves the following process steps:

1) coal preparation,
2) gasification,
3) tar and dust removal,
4) shift conversion,
5) acid gas removal,
6) methanation, and
7) drying and polishing methanation.

These are illustrated schematically in Figure 3-1.

Coal preparation varies somewhat depending upon the specific gasification process. Generally, coal must be crushed to a relatively fine size. For some processes, however, sizes less than 1/8 inch cannot be accepted, and briquetting of

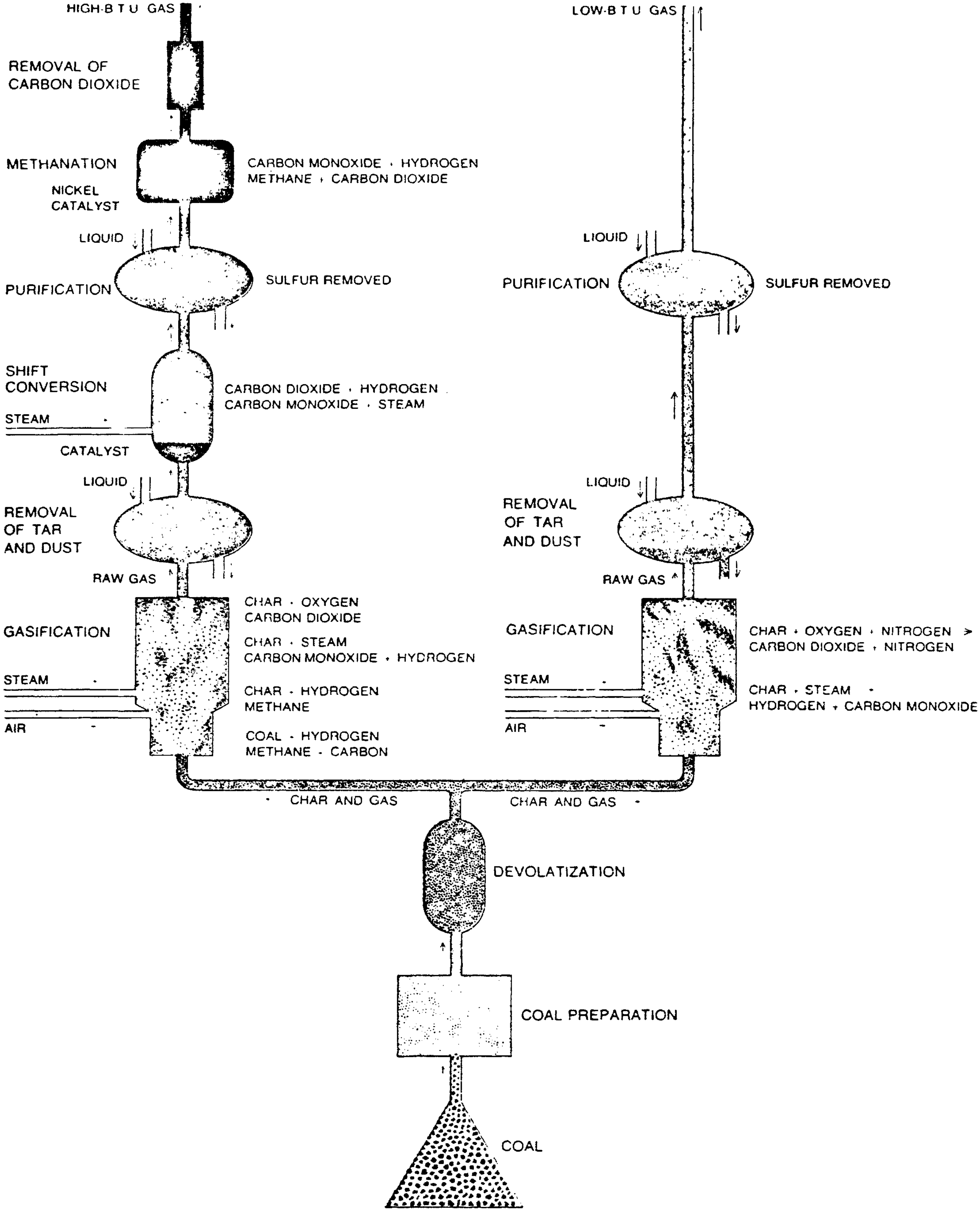


Figure 3-1. Steps in Coal Gasification (after Perry, 1974).

such fines may be employed. For processes which cannot accept agglomerating coal, prepreparation involving mild air oxidation may also be required. In all cases, conventional coal cleaning for rock removal is carried out.

The gasification step generally distinguishes the various proposed approaches to SNG production. In most cases oxygen and steam are injected into the gasification chamber to react with devolatilized coal (char). Many different contact methods are used, including fixed, moving, and fluidized-bed reactors as well as free fall. Coal may be fed by means of lock hoppers or as a slurry. Some or all of the following reactions occur in the gasification chamber (Mudge, et al., 1974):

oxidation of char:

$$C + O_2 \longrightarrow CO_2 + \text{heat} \tag{1}$$

gasification of char with carbon dioxide:

$$C + CO_2 + \text{heat} \longrightarrow 2\ CO \tag{2}$$

water-gas reaction:

$$C + H_2O + \text{heat} \longrightarrow CO + H_2 \tag{3}$$

methanation of char:

$$C + 2\ H_2 \longrightarrow CH_4 + \text{heat} \tag{4}$$

water-gas shift reaction:

$$CO + H_2O \longrightarrow CO_2 + H_2 + \text{heat} \tag{5}$$

hydrogen oxidation:

$$H_2 + 1/2\ O_2 \longrightarrow H_2O + \text{heat} \tag{6}$$

Oxidation of char, reaction (1), is used in many processes to provide heat for the endothermic reactions (2) and (3). Methanation of char, reaction (4), is highly exothermic and also provides heat for reaction (3). In some systems, electrical resistance heating, or an externally fired inert material such as molten salt, metal, or dolomite is used as a heat source. Typical effluent gas composition for a steam-oxygen Lurgi process using bituminous coal is given in Table 3-1. The heating value of this gas after carbon dioxide removal is about 450 Btu/SCF. From an economic standpoint, it is important to produce as much methane as possible in the initial gasification stage (in order to reduce the need for the subsequent methanation step), and to achieve

Gas Component	Gas Produced (Volume Percent)
CO_2	27.5
CO	21.0
H_2	41.0
CH_4	8.8
N_2	0.4
Other	1.3
Total	100.0

Table 3-1. Typical Gasifier Effluent Composition Lurgi Process (Mudge, et al., 1974).

a high ratio (about 3:1) of hydrogen to carbon monoxide (in order to reduce the need for the subsequent shift conversion steps). Gasifiers are generally being planned to operate at the high temperatures (1100-2500°F) and pressures (300-1400 psi) favorable to the above reactions.

Tar and dust removal follows the gasification stage. Direct water quenching or scrubbing precedes cyclones, sand filters, electrostatic precipitators, or mechanical collectors. The presence of hydrogen sulfide makes the gas highly corrosive, and research is being conducted on metal problems in this step.

The ratio of hydrogen to carbon monoxide must be adjusted in a shift conversion step prior to final methanation. Additional steam is used to catalytically shift carbon monoxide to hydrogen and carbon dioxide as follows:

$$CO + H_2O \longrightarrow CO_2 + H_2 + \text{heat} \qquad (7)$$

The reaction is only slightly exothermic. This step is commercially proven and few problems are foreseen.

Further purification is necessary following shift conversion to remove hydrogen sulfide and carbon dioxide formed in the gasifier, as well as additional carbon dioxide produced in the shift conversion. Many physical and chemical absorption processes are available to accomplish this step. Hydrogen sulfide can be further processed to elemental sulfur as a by-product.

Catalytic methanation serves to combine hydrogen and carbon monoxide to form methane as follows:

$$CO + 3\,H_2 \longrightarrow CH_4 + H_2O + \text{heat} \tag{8}$$

The reaction must occur at temperatures below 900°F to avoid distruction of the nickel catalyst. Methanation serves to form a high heat-content fuel (methane), while at the same time reducing carbon monoxide to a nontoxic level. The methanation step has not been commercially proven, however, and much research remains to be conducted in this area.

The final step in coal gasification involves drying the methanator effluent gas and passing the dried gas over a final polishing methanator to remove the remaining small amounts of carbon oxides. Since heat release at this stage is minimal and carbon oxide amounts are small, commercial methanators can be used. The resulting gas has a heat content of about 950 Btu/SCF and is essentially equivalent to natural gas.

Low-Btu gas production allows the elimination of the most troublesome process steps involved in manufacturing high-Btu gas. These are shift conversion and methanation. In addition, the acid gas removal step is made less costly since carbon dioxide no longer has to be removed. The gasification step is also more economical since air can now be used in place of commercial oxygen. After gasification, tar and dust are removed, and sulfur compounds are eliminated. The process is illustrated in Figure 3-1. Resulting gas has a heat content of from 150-250 Btu/SCF and a composition as shown in Table 3-2.

3.2.2 Plant projections

Technology for high-Btu coal gasification is still under intensive development.

Gas Component	Percent by Volume
CO_2	3-10
CO	15-30
H_2	12-25
CH_4	2- 6
N_2	40-60

Table 3-2. Typical Composition of Low-Btu Gas (Source: Federal Power Commission, 1973).

For this reason, it is difficult to predict the growth of the SNG industry. One projection, that of the Synthetic Gas-Coal Task Force of the Federal Power Commission, is given in Table 3-3. Plants projected to be constructed through the year 1980 are based entirely upon extensions of the Lurgi Process (currently used for intermediate-Btu gas production), while all plants constructed after 1985 are assumed to be of advanced design ("new processes").

Year	Number of Plants	Capacity (trillion CF/year	Cumulative Investment (million dollars)
1975	None	None	None
1980	5	0.4	1,727.3
1985	16	1.3	5,870.7
1990	36	2.9	13,889.9

Table 3-3. Projection of Commercial, High-Btu Coal Gasification Plants (Source: Federal Power Commission, 1973).

Commercially available, intermediate-Btu coal gasification processes are the Lurgi, Koppers-Totzek, and Winkler processes. Examples of advanced processes under development for SNG production are: 1) Hygas, 2) CO_2-acceptor, 3) Synthane,

4) Bi-Gas, 5) Union Carbide-Battelle ash agglomeration, 6) Kellogg's molten salt, 7) Atgas, and 8) Hydrane. Detailed descriptions of these are available in the literature (e.g., see Kermode, et al., 1973, Mudge, et al., 1974, and National Academy of Engineering, 1973).

The advanced processes are designed to overcome certain shortcomings of the Lurgi process. Among these are: 1) the inability to handle caking coals (those that agglomerate upon heating, such as Midwestern and Eastern U. S. coals), and 2) the inability to use fine coal sizes (less than 1/8 inch). In addition, the advanced processes should be lower in total cost by using less oxygen and by attaining greater thermal efficiency.

3.3 Water Requirements

Water is consumed in SNG production through process chemical reaction and through evaporative cooling losses. Additional water consumption occurs at the mine through dust control and miscellaneous uses, and at raw water storage ponds through evaporation. Some consumptive loss also occurs through secondary uses, such as for project-related domestic, industrial and commercial water supplies. Only process and evaporative losses will be investigated herein.

The overall chemical reaction of coal gasification is to combine carbon with hydrogen to form methane. Water is the principal source of hydrogen in this reaction. Water is consumed in the gasifier chamber during the water-gas reaction (3) and the water-gas shift reaction (5), indicated above. Since hydrogen is furnished by reactions (3) and (5) for reaction (6), hydrogen oxidation, the latter cannot significantly alter a condition of net water loss in the gasifier. Shift conversion, reaction (7), also requires water. Some water is produced during methanation, reaction (8), but again, not enough is gained to offset previous water consumption. Literature estimates vary somewhat for the overall process water requirement. On a strict molar basis, if all of the hydrogen were to be furnished by input water for a high-Btu plant producing 250 MMSCF/day, a water consumption of 1985 gpm (2.86 MGD, or 3200 AF/year) would be indicated. Since process efficiency is not entirely known, however, this estimate is probably low. On the other hand, coal itself contains some moisture and also has available some chemically bound hydrogen. This would serve to reduce process water needs. Many references (Federal Power Commission, 1973, Schmetz, et al., 1974, and Davis and Wood, 1974) adopt water consumption estimates as given by the American Gas Association (1971). These are shown in Table 3-4. Process water consumption is estimated at 1742 gpm, and boiler water make-up at 396 gpm, for bituminous and sub-bituminous coals.

The principal source of water consumption in coal gasification, however, is not in the process itself, but rather in losses associated with cooling water needs. As in all thermodynamic processes, energy is lost in the conversion from one form of energy to another, and heat is rejected to the environment. Thermal efficiency

	Bituminous and Sub-Bituminous Coal			Lignite		
Percent Makeup of Total Cooling Water Circulated	3%	5%	7%	3%	5%	7%
Process water, gpm	1,742	1,742	1,742	1,705	1,705	1,705
Boiler Makeup, gpm	396	396	396	359	359	359
Cooling Water Makeup, gpm	12,107	20,178	28,249	10,096	16,828	23,559
Total Water Consumed,						
gpm	14,245	22,316	30,387	12,160	18,892	25.623
AF/year	22,934	35,928	48,923	19,577	30,416	41,253
MGD	20.5	32.1	43.8	17.5	27.2	36.9
Water Requirements with Partial Air Cooling,						
gpm	7,123	11,158	15,194	6,080	9,446	12,812
AF/year	11,468	17,964	24,462	9,789	15,208	20,628
MGD	10.3	16.1	21.9	8.8	13.6	18.5

Table 3-4. Water Consumption of a Typical High-Btu Plant (Source: Federal Power Commission, 1973, and American Gas Association, 1971).

for coal gasification ranges from 60 to 75 percent, depending upon the particular process being used. The amount of heat rejected from a standard 250 MMSCF/day coal gasification plant can be compared to other energy sources as shown in Table 3-5.

Type of Energy Facility	Heat Rejection (10^9 Btu/hour)
Fossil-fueled power plant (100 MWe)	4.4
Nuclear power plant (1000 MWe)	7.0
High-Btu coal gasification plant (250 MMSCF/day)	5.3
Low-Btu coal gasification plant (1360 MMSCF/day)*	2.5

* Same total energy content as 250 MMSCF/day high-Btu gas.

Table 3-5. Heat Rejection by Typical Energy Conversion Facilities (Source: MacFarlane, et al., 1975, p. 90).

The exact amount of heat transmitted to the environment through cooling waters depends upon the type of energy conversion facility. The amount of cooling water consumptive loss, in turn, depends upon the type of cooling system that is utilized. Some possible systems are air cooling (dry cooling towers), wet cooling towers, cooling ponds, spray ponds, or natural lake or river discharge. Coal gasification plant, cooling water consumptive use as estimated by the American Gas Association is given in Table 3-4 for various make-up rates, and assuming that wet cooling towers are to be used. The extent to which make-up waters are needed depends to a great degree on the quality of the fresh-water supply. Brackish or highly turbid waters would lead to increased blowdown from cooling towers in order to maintain cooling water quality. A 7 percent make-up rate may be appropriate under such circumstances. For high-quality supply water, a 3 percent make-up rate would apply. The range of total water consumption under such conditions is from 14,245 gpm (20.5 MGD, or 22,934 AF/year) to 30,387 gpm (43.8 MGD, or 48,923 AF/year). When air cooling (dry cooling towers) is utilized, the American Gas Association estimates that total water consumption can be cut by one-half, as shown in Table 3-4.

Water consumption estimates for low-Btu coal gasification plants closely follow those for high-Btu plants. Brill and Provenzano (1974) summarize data indicating a water consumption of from 8500 gpm to 10,100 gpm for low-Btu plants having an equivalent energy output of a standard 250 MMSCF/day high-Btu plant. Davis and Wood (1974) state that the water consumption for a low-Btu plant should be equivalent to that for a high-Btu plant on a per unit Btu basis. Heat rejection for a low-Btu plant, however, is only about one-half that of a high-Btu plant, as shown in Table 3-5. This should significantly reduce losses from cooling water evaporation in the low-Btu plants.

3.4 Water Demand

Actual water consumption for a coal gasification facility will be determined by an interaction of relative water availability or cost, and technological features of the plant. In economic terms, the quantity of water consumed at any given facility should depend upon the price, or cost, of the raw water supply. Ideally, a condition of water scarcity would be reflected in an increased purchase price. In the Western United States, however, a system of water rights replaces the price mechanism to a large degree. Water scarcity is therefore generally reflected in low levels of allocated water to any particular user. Water conservation schemes are adopted to allow operations based upon this allocation.

One commercial-size coal gasification plant has been designed under conditions of water scarcity. The Western Gasification Company (WESCO) has contracted with Fluor Engineers and Constructors, Inc. for the design of a 250 MMSCF/day high-Btu plant in New Mexico about 25 miles south of Farmington. The total raw water available from the San Juan River is contractually limited to 44,000 AF/year by the U. S. Department of the Interior. With four gasification plants ultimately planned for, each plant could consume no more than 11,000 AF/year. This figure lies at the lower end of the water consumption estimates shown in Table 3-4 for the case assuming air cooling. Water consumption at the WESCO plant, however, is projected to be only 8,260 AF/year (5100 gpm, or 7.4 MGD), or about 75 percent of the contract water supply available for one plant. This is to be achieved through intensive recycling within the coal gasification process. Details of the recycling scheme are given in Paquette and Beychock (1973), Strasser (1973) and Battelle Columbus Laboratories (1973). The ultimate disposition of influent water is shown in Table 3-6. Only about 10 percent of total water consumption occurs in the process itself, while about 70 percent is accounted for by various sources of evaporation.

Process Consumption	GPM	%
To supply hydrogen	1,120	
Produced as methanation byproduct	-600	
Net consumption	520	10.2
Return to Atmosphere		
Evaporation:		
From raw water ponds	420	
From cooling tower	1,760	
From quenching hot ash	150	
From pelletizing sulfur	250	
From wetting of mine roads	730	
	3,310	
Via stack gases[1]:		
From steam blowing of boiler tubes	200	
From stack gas SO_2 scrubbers	40	
	240	
Total return to atmosphere	3,550	69.6
Disposal to Mine Reclamation		
In water treating sludges	100	
In wetted boiler ash	30	
In wetted gasifier ash	300	
Total disposal to mine	430	8.4
Others		
Retained in slurry pond	20	
Miscellaneous mine uses	580	
Total others	600	11.8
GRAND TOTAL	5,100	100.0

[1] Does not include water derived from burning of boiler fuel.

Table 3-6. Disposition of Water Consumption in the WESCO High-Btu Plant (Source: Paquette and Beychock, 1973).

Another commercial coal gasification facility has been designed by El Paso Natural Gas Company for a site near the WESCO plant site in arid New Mexico. The plant is to produce 288 MMSCF/day of pipeline quality gas. A water supply of 28,250 AF/year has been allocated for plant use from the San Juan River at Bloomfield. Since three plants are to be constructed ultimately, each plant could use no more than about 9400 AF/year for its water supply. As in the WESCO design, intensive recycling of plant flow streams is to be carried out (Milios, 1975). Total raw water consumption for the plant is estimated at 5,622 gpm (8.1 MGD, or 9,070 AF/year). Mine, offsite users, and storage pond evaporation account for an additional 1,434 gpm of losses. Ultimate disposition of the plant water closely resembles that of the WESCO plant, with about 67 percent evaporated and 24 percent chemically consumed to produce synthetic gas. In both the WESCO and El Paso plant designs, no return flows or liquid waste discharge are permitted, since total consumption of the plant inflow is planned.

3.5 Water Use for Southeastern Ohio

Based upon the above data, water consumption can be estimated for typical coal gasification facilities that may be constructed in Southeastern Ohio. With water supplies generally plentiful, little incentive will exist to conserve water to the extent practiced at the WESCO or El Paso sites. Water quality in streams and aquifiers in Southeastern Ohio is also good with respect to dissolved solids. Occasional turbidity problems will be present, however. Water consumption for high-Btu plants could therefore be expected to range from 20 to 30 MGD (13,790 to 20,700 gpm, or 22,300 to 33,400 AF/year), roughly approximating cooling water make-up rates of from 3 to 5 percent. It is also assumed that low-Btu plants will consume this same amount of water in producing the equivalent of 250 MMSCF/day of high-Btu gas.

To test the sensitivity of potential site locations to relative water availability, a range of water consumption estimates will be used in the analysis to follow. It will be assumed that water consumption values of 10, 25, and 40 MGD are possible for a standard 250 MMSCF/day high-Btu plant. These would correspond to low, most likely, and high water use estimates for plants located in Southeastern Ohio.

Chapter 4 - WATER AVAILABILITY IN SOUTHEASTERN OHIO

4.1 Introduction: National Water Availability for Energy

A number of overview studies have been carried out to determine whether water availability will be a limiting factor in the future development of the Nation's energy supplies. In the first such study to be conducted, the American Gas Association set as a goal to determine the availability and location of coal and water resources adequate to serve a coal gasification industry. The study found adequate coal reserves east of the Mississippi River to support 35 plants. Western coal reserves were found to be adequate for 141 plants. Water supplies were identified to adequately serve all 176 plants at specific locations. Conclusions regarding the relative accessibility of water supplies cannot be drawn from this study, however, since the detailed study report is proprietary and only an abbreviated version is available (American Gas Association, 1971). The abbreviated study does not indicate specific site locations.

The U.S. Water Resources Council (1974) has undertaken an extensive, non-quantitative analysis of water availability for energy in the U.S. A major conclusion is that adequate water supplies will be a constraint on reaching energy self-sufficiency. In five Water Resources Council Regions, improved water management, reallocation of supply, and/or augmentation may be required. These are the Upper and Lower Colorado, Great Basin, Rio Grande, and Souris-Red-Rainy Regions. In nine other regions, additional storage is seen as a principal need. Among these are the Ohio, Great Lakes, Upper Mississippi, Middle Atlantic and Missouri Regions. In addition, the problem of water scarcity may be increased significantly in the West if extensive reclamation of mined lands is to be carried out. This is particularly true in the Colorado River area (National Academy of Science, 1973).

The Upper Colorado River Basin, if compared to the other basins, is probably the most water deficient relative to future energy development plans. The Upper Colorado River surface water supply is already over-appropriated. Water for energy must therefore be obtained through water rights transfers from agricultural users. Groundwater is also expected to provide some of the Basin's future needs, and extensive use of conservation measures such as air cooling will have to be implemented at energy development facilities (U.S. Department of the Interior, 1974).

In one of the most detailed studies of coal and water resources for coal conversion, Smith and Stall (1975) have documented the adequacy of coal and water supplies for coal gasification and/or liquefaction in Illinois. The authors found 228 locations where a potential reservoir capable of supplying more than 6 MGD of water could be built. In addition, 17 areas in the state were identified where water-well systems could be developed to yield an estimated 14 to 72 MGD. The latter are principally in sand and gravel aquifers lying within major valley systems. It was concluded that Illinois could support a major coal conversion industry without incurring significant water supply deficiencies. In certain localities, however, rather extensive water supply development projects would be necessary. An earlier study conducted in the same state by Seay, et al (1972), indicated that the cost of water development for coal gasification plants may add from 0.6¢ to 9.0¢ per thousand cubic feet to the cost of synthetic pipeline quality gas, depending on the location of the plant site. It was estimated that each 10¢/1000 gallons increase in the cost of water would result in a gas cost increase of about 0.6¢/MCF for a plant water requirement of 10,000 gpm (14.4 MGD, or 16,130 AF/year). It is evident that the availability of water at a specific site may significantly affect gas price.

In the sections that follow, water availability for coal gasification plants in Southeastern Ohio will be investigated. Surface water sources, existing and potential reservoir sites, and groundwater development will be considered as potential sources of supply. The relative cost of such supplies will be evaluated and general conclusions drawn.

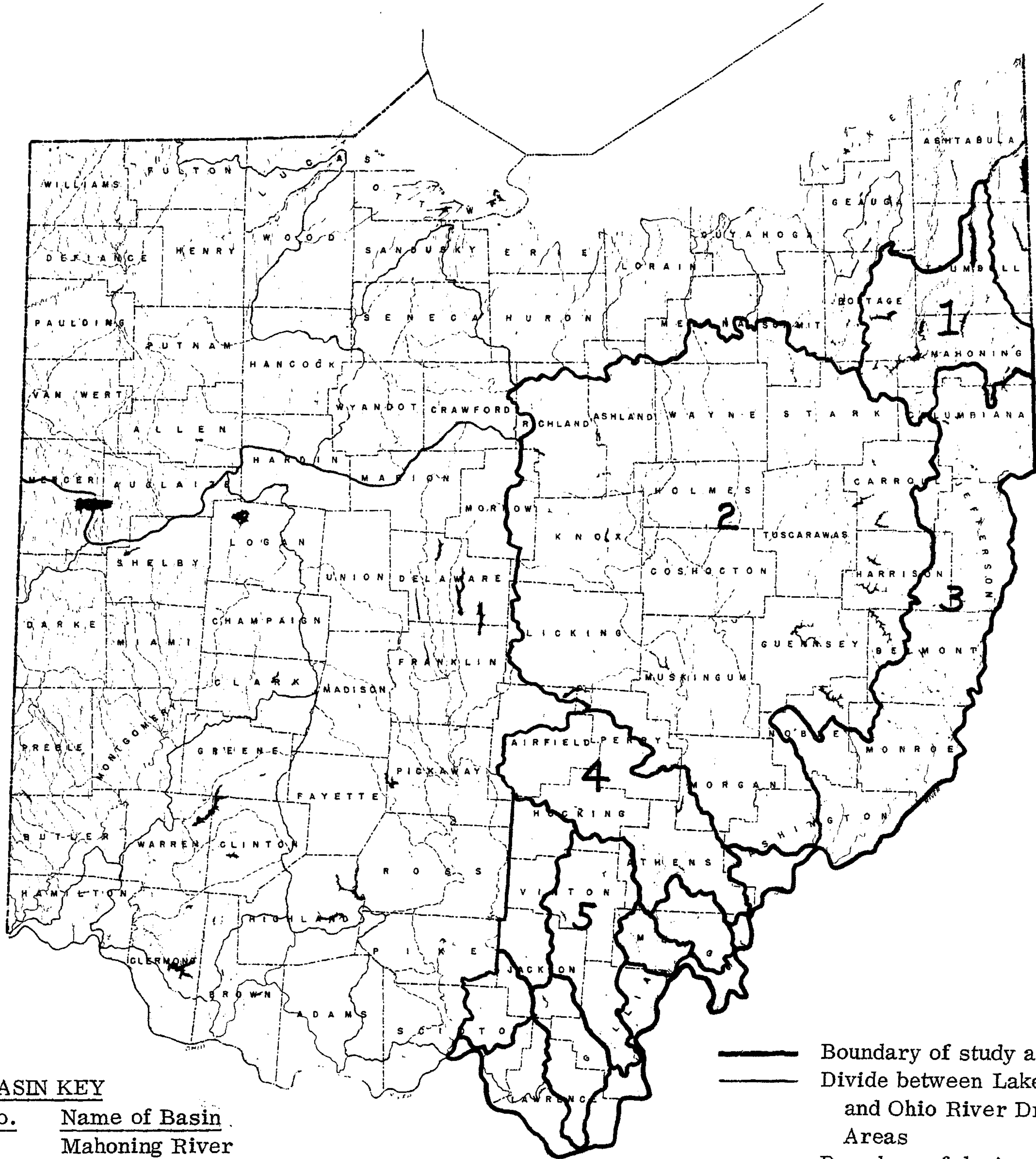
4.2 Hydrologic Study Area

A map of the selected study area is shown in Figure 4-1. The boundary of the study area was selected to include the major coal producing counties of Ohio as well as the major streams flowing through or near these counties. In most cases the boundary is therefore determined by watershed basins of the area. Major basins studied are the Hocking, Muskingum, and Mahoning, along with those smaller streams draining directly to the Ohio River.

4.2.1 Surface water low-flow

Direct use of surface waters as a source of supply for coal gasification plants depends upon the stochastic nature of stream low-flows. For purposes of this report, the 7-day duration, once-in-10-year low-flow will be taken as a valid indicator of streamflow dependability. A judgment must also be made as to the acceptability of relative withdrawal levels, since coal gasification is a consumptive use of such low-flows. It will be assumed that no more than a 10 percent consumptive use of the 7-day, 10-year low-flow will be allowed for any given stream. For the assumed coal gasification consumptive uses of 10, 25, and 40 MGD, such streamflows would have to be 100, 250, and 400 MGD, respectively. In this connection, it is of interest to note the conclusions of a recent study of the effects of streamflow availability on the location decisions of manufacturing firms in the Tennessee Valley region (Garrison and Paulson, 1972). It was found that the threshold 7-day, 10-year low-flow, above which concentrations of at least 500 employees in water-oriented manufacturing occurred, was in the neighborhood of 262 MGD (400 cfs). Evidence was presented to indicate that water availability is a significant factor in the microlocation decision of such firms.

Figure 4-2 shows those portions of streams in the study area which have 7-day, 10-year low-flows of 25 and 250 MGD. It can be seen that although only major, main-streams have flows greater than either of those designated, this still leaves relatively large areas adjacent to streams whereon sites for CG plant complexes could be sought. Selection of such sites would have to be made with consideration given to coal transport costs and the location of final gas demand, however.



BASIN KEY

No.	Name of Basin
1	Mahoning River
2	Muskingum River
3	Ohio River Tributaries
4	Hocking River
5	Raccoon Creek

Boundary of study area

Divide between Lake Erie and Ohio River Drainage Areas

Boundary of drainage subarea.

Figure 4-1. Map of Hydrologic Study Area.

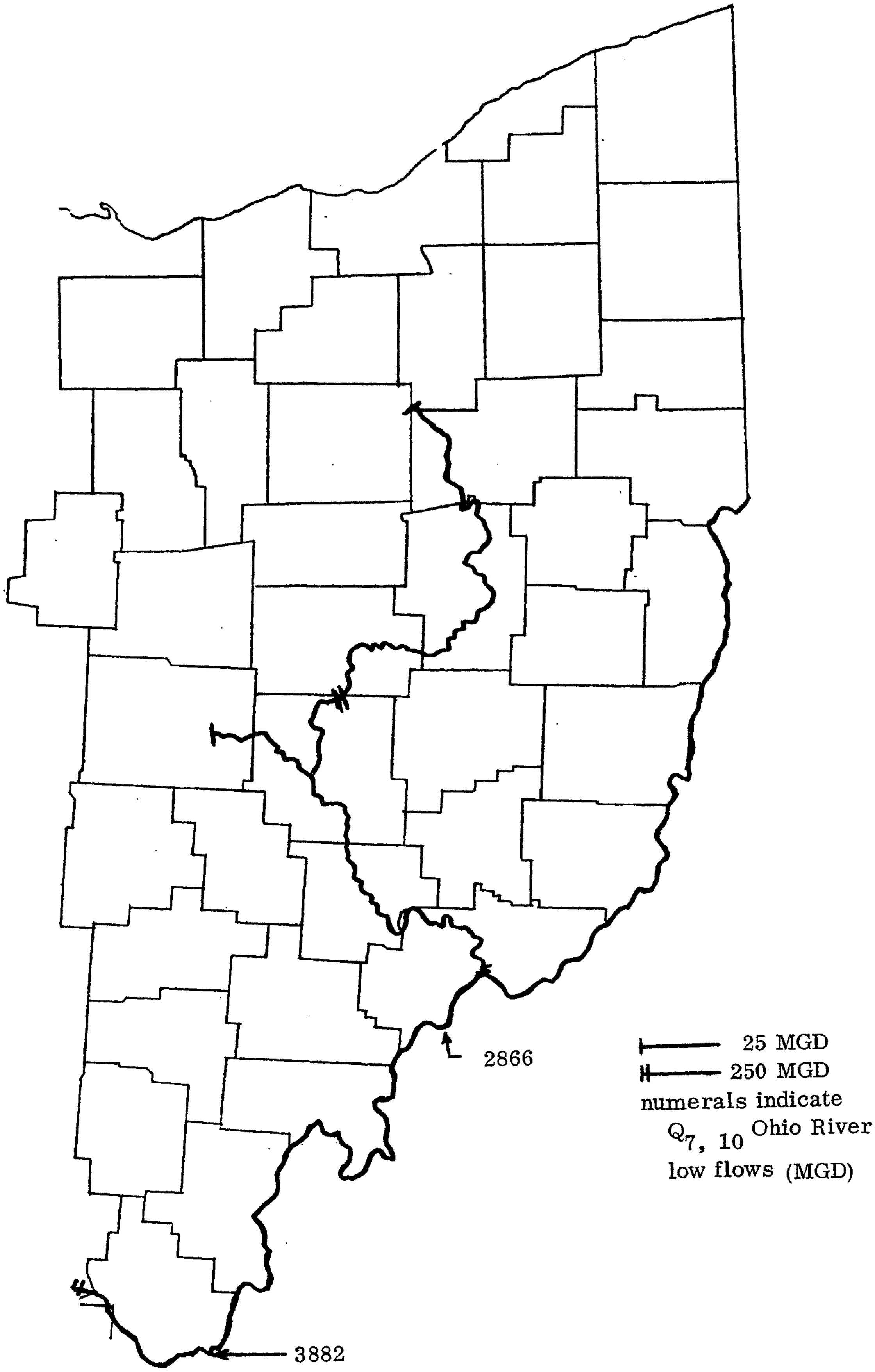


Figure 4-2. Stream Low-Flows

4.2.2 Surface Water Impoundment

It is natural to ask to what extent reservoirs could be used to supply the consumptive water demands of coal gasification plants. A large number of reservoirs already exist in the study area. These are listed in Table 4-1. Flood control is the most common purpose of existing reservoirs, with most of these incorporating some recreational uses as well. Few reservoirs have water supply as a major purpose. This is mainly caused by the abundance of groundwater or surface water supplies in the area, relative to a rather diffuse, rural population.

Generalized data exist to determine the feasibility of achieving a stated water supply yield for any stream in Ohio. These are found in Bulletin 40 of the Ohio Department of Natural Resources (Cross, 1965). Bulletin 40 was used to determine points on streams in the study area below which average-sized reservoirs, if constructed, would yield 25 MGD, the consumptive use assumed for a coal gasification plant. From Table 4-1 the average capacity-to-flow ratio (C/Q)was found to be 0.70 for existing reservoirs in the study area. A generalized map was constructed to indicate those portions of streams in the study area which could provide 25 MGD water supply through reservoirs of this relative size. It was assumed that sites could be found in the study area to accomodate reservoirs of this average size. To the extent that suitable reservoir sites do not exist on certain reaches of demarcated streams, such a map is inaccurate. However only detailed field reconnaissance will enable this to be determined. For the purposes of this study it is sufficient to indicate the relative availability of water supplies from surface water impoundments. Also, impoundments on the mainstream of very large rivers such as the Muskingum, are generally impractical. Demarcation of such portions of rivers should be done only when suitable reservoir sites exist on tributary streams, so as to ensure the desired yield on the mainstem through flow routing. There is no difficulty in this regard for streams in the study area since 1) upstream sites in general do exist, and 2) such mainstem rivers in the study area have sufficient natural low-flow to serve adjacent CG plants without additional storage.

Table 4-1: Data on Existing Reservoirs in the Study Area. (Source: U.S. Geological Survey, 1970)

Basin & Reservoir Name	Reservoir* Purpose	Drainage Area (Sq. Miles)	Total Reservoir Capacity: Acre-feet	Total Reservoir Capacity: Million Gallons	Stream Average Discharge, Q (MGD)	Capacity to Flow Ratio (C/Q)	Location (Stream)
Mahoning R. B.							
Berlin Res.	FWA	248.0	91,150.00	29,213.58	150.0	0.5336	Mahoning River
Milton Res.	WA	273.0	29,150.00	9,342.58	210.0	0.1220	Mahoning River
West Branch Res.	F AR	80.5	78,700.00	25,223.35	50.0	1.3820	W. Branch Mahoning R.
Mosquito Creek Res.	FWA	97.5	104,100.00	33,364.00	60.0	1.5230	Mosquito Creek
Meander Creek Res.	W	83.9	32,410.00	10,387.41	52.0	0.5470	Meander Creek
Muskingum R. B.							
Bolivar Res.	F	504.0	149,600.00	47,946.8	320.0	0.4100	Sandy Creek
Leesville Res.	F	48.3	37,400.00	11,986.7	32.0	1.0260	McGuire Creek
Atwood Res.	F	69.9	49,700.00	15,928.9	45.8	0.9530	Indian Fork
Dover Res.	F	1404.0	203,000.00	65,061.5	890.0	0.200	Tuscarawas River
Beach City Res.	F	300.0	71,700.00	22,949.9	195.0	0.3230	Sugar Creek
Piedmont Res.	F	85.9	65,000.00	20,832.5	56.0	1.0190	Stillwater Creek
Clendening Res.	F	69.3	54,000.00	17,307.0	45.8	1.0350	Brushy Fork
Tappan Res.	F	71.1	61,600.00	19,742.8	46.0	1.1760	Little Stillwater Cr.
Charles Mill Res.	F	215.0	88,000.00	28,204.0	140.0	0.5520	Black Fork
Pleasant Hill Res.	F	197.0	87,700.00	28,107.9	128.0	0.6020	Clear Fork
Mohicanville Res.	F	271.0	102,000.00	32,691.0	172.0	0.5210	Lake Fork
Mohawk Res.	F	1504.0	285,000.00	91,342.5	950.0	0.2630	Walhonding River
Senecaville Res.	F	118.0	88,500.00	28,364.3	77.0	1.0090	Seneca Fork
Salt Fork Res.	FW R	159.0	71,800.00	23,011.9	102.0	0.6180	Salt Fork
Wills Creek Res.	F	842.0	196,000.00	62,818.0	540.0	0.3180	Wills Creek
Dillon Res.	F	742.0	274,000.00	87,817.0	470.0	0.5120	Licking River

Average C/Q Ratio 0.70

*F: Flood Control
W: Water Supply
A: Low-Flow Augmentation
R: Recreation

The method of calculating the areal extent of suitable reservoir sites can be explained with the use of Figure 4-3, adapted from Bulletin 40:

1) From Bulletin 40 for all furthest upstream gaging stations in the study area, obtain:

   a) the low-flow index, L_I, where:

      L_I = consecutive 7-day low flow with a recurrence interval of once in 10 years divided by the average streamflow;

   b) the average discharge per unit watershed area, q (MGD/mi^2);

2) From Bulletin 40, Plate 20 (Southeast Ohio) or Plate 23 (Northeast Ohio) enter L_I as above, and C/Q = 0.70. Determine R/Q_r where:

   R/Q_r = ratio of desired yield (25 MGD) to average streamflow at reservoir site;

3) Determine necessary average streamflow at reservoir site as

   $Q_r = R \div$ Ratio of Step (2):

4) Determine necessary contributing area to the reservoir site as

   $$A_r = \frac{Q_r}{q}$$

5) Determine necessary reservoir capacity (MG) as

   $C_r = .70\ (365)\ Q_r$

Results of this analysis for the study area are shown in Table 4-2. For Southeast Ohio, an average reservoir capacity of about 8.8 billion gallons is necessary to yield a 25 MGD flow (with shortage probability of 0.05). The reservoir would also have about 55 square miles of contributing area, and an average streamflow of about 37 MGD. In Northeast Ohio, a somewhat smaller average reservoir capacity of 7.2 billion gallons would be sufficient. The corresponding contributing area would be about 47 square miles, resulting in an average streamflow of 30 MGD.

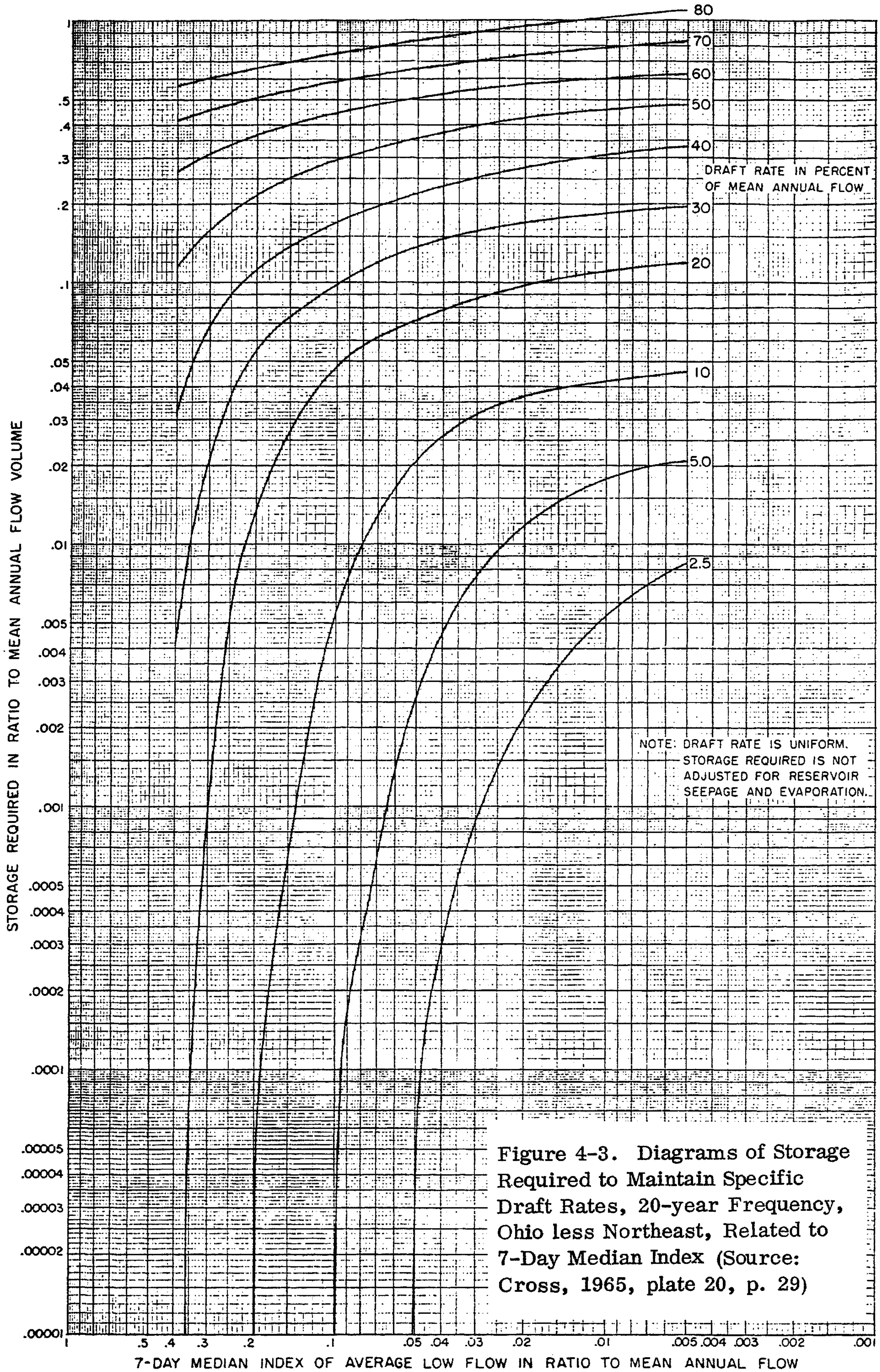


Figure 4-3. Diagrams of Storage Required to Maintain Specific Draft Rates, 20-year Frequency, Ohio less Northeast, Related to 7-Day Median Index (Source: Cross, 1965, plate 20, p. 29)

Study Area	Reservoir Average Capacity (million gallons)	Average Contributing Area (square miles)	Average Streamflow at Site (MGD)
Southeast Ohio:			
Muskingum R.	8650	60.0	36.4
Hocking R.	7984	54.3	33.8
Various SE	9553	55.3	40.3
Ohio R. Trib.	9107	50.0	38.0
Northeast Ohio:			
Muskingum R.	7130	47.1	30.0
Ohio R. Trib.	7218	44.5	30.5
Beaver R.	7236	49.6	30.5

Table 4-2. Reservoir and Watershed Characteristics for a 25 MGD Yield for Study Area.

Decreased reservoir size requirements and watershed characteristics for Northeast, as compared to those for Southeast, Ohio, are caused by a distinct difference in low-flow regime between the two geographic areas. Bulletin 40 states that low-flow periods in Northeast Ohio are often broken by hurricane storm movements. These are not as common in Southeast Ohio, and a separate low-flow analysis is made in Bulletin 40 for Northeast Ohio as compared to the rest of the state. Since Southeast Ohio comprises most of the study area, and since most coal supplies are found in this sector, subsequent economic analysis in this report will be based upon reservoir data from this portion of the study area.

Those portions of streams which could support a 25 MGD yield through construction of average-size reservoirs are shown in Figure 4-4. It is evident that streams of this type are abundant in the study area. It would be expected, therefore, that reservoir sources of water for a coal gasification plant complex should be

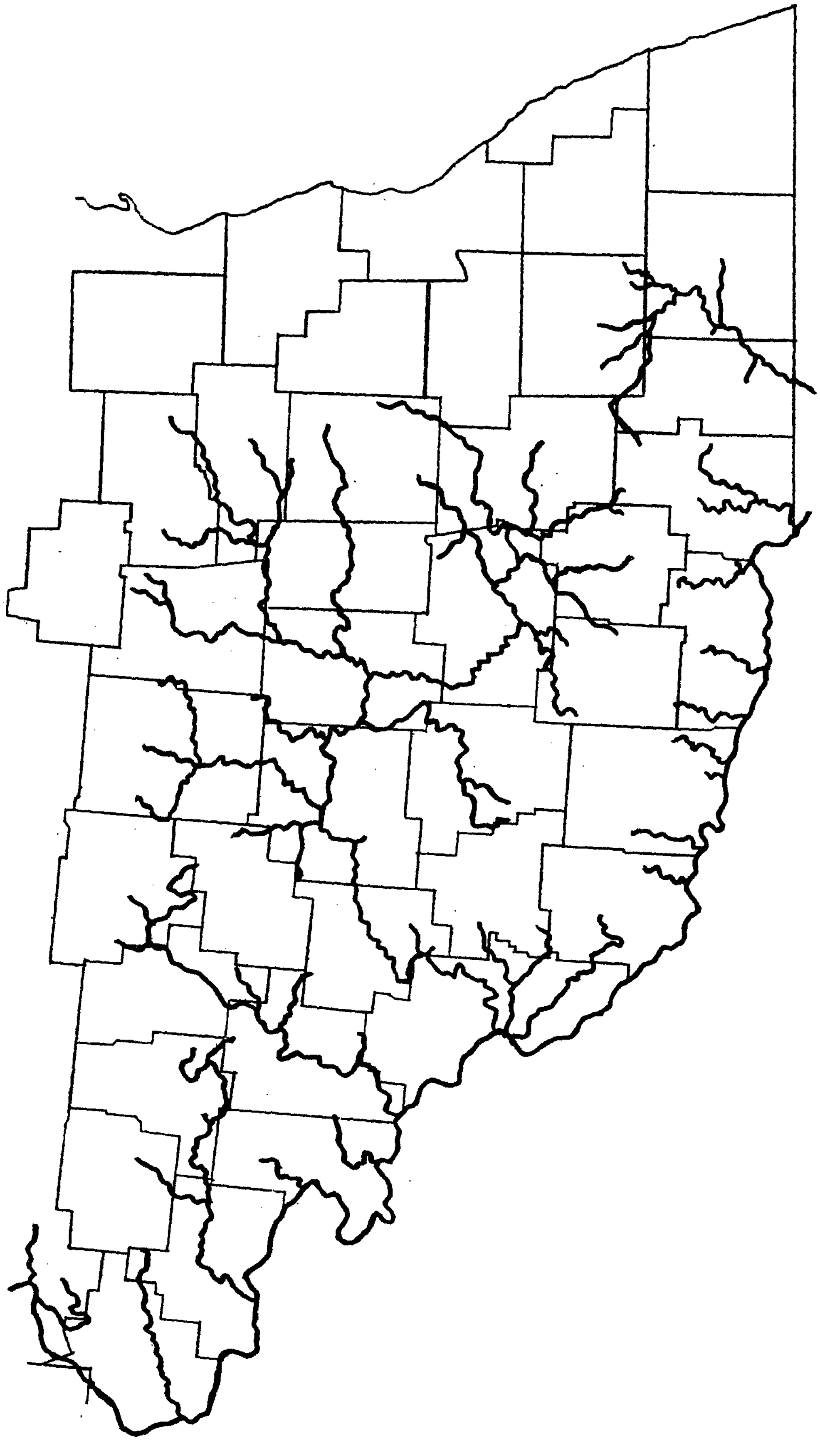


Figure 4-4. Generalized Stream Portions Capable of Sustaining Desired Yield with Average-Size Reservoirs.

relatively abundant. Again it is emphasized, however, that some streams indicated in Figure 4-4 may not have suitable reservoir sites, even though they are otherwise hydrologically capable of supplying desired yields. This may be the case due to environmental, geologic, or other factors. Only detailed reconnaissance studies can finally determine this.

Another source of water supply that should be given some attention is the possible conversion of some portion of existing flood control storage to water supply uses. Existing reservoir storage for flood control in the study area is very large, as indicated in Table 4-1. Conversion of only a portion of such storage to water supply uses would represent a considerable increase in available water supplies. Significant legal, institutional, and economic aspects must be considered in such a conversion, however. National priorities and the severity of gas shortages will determine whether such conversions will be sought.

4.2.3 Groundwater

Based upon a required yield of 25 MGD to serve a CG plant of standard size, few geographical regions in the study area would have sufficiently high groundwater yields to provide a dependable and economical source. Nevertheless, these areas are distributed in such a manner as to represent potential alternative sources to surface water supplies. Generally, the groundwater yield at individual wells would have to approximate 500 gpm before a well field development could economically provide the relatively large water requirement of a coal gasification plant.

Yields of 500 gpm can generally be obtained only in glacial outwash and alluvial sand and gravel deposits of the major river valleys in the study area. These are the Tuscarawas, Walhonding, Licking, Muskingum, Hocking and Ohio River valleys. Wells drilled into these aquifers would generally benefit from recharge from the adjacent river. A map indicating the distribution of these aquifers is shown in Figure 4-5. On the basis of geographical distribution, the results of the current investigation are similar to those of Smith and Stall (1975) for basins in Illinois. In their study, only 17 rather limited geographical areas of Illinois were found to be able to provide sufficient well-water supplies for coal conversion facilities. These were mainly in unconsolidated, alluvial valley deposits found along major river courses.

Table 4-3 summarizes data for the four principal alluvial valley aquifers in the study area, along with the Ohio River. Since coal gasification plants generally require water of boiler water quality, groundwater sources will have to be treated to reduce hardness. Natural hardness ranges from 150 to 900 mg/l for the major groundwater sources. Total dissolved solids range from 150 to 1000 mg/l.

The extent of possible groundwater development can be exemplified by calculations made by Carlston and Graef (as reported in Deutsch, et al, 1969, p. 3-7) for a section of the Ohio River near Moundsville, West Virginia. They estimated that a yield of at least 26 MGD could be developed per mile of valley length along the river section under study. If multiplied by the total length of mainstem streams in the study area, this represents a very large water supply source that could potentially be developed.

4.3 Water Supply Economic Analysis

The ultimate source of water for a coal conversion industry will be determined on the basis of costs incurred. In previous sections, alternative water supply sources were investigated from a hydrologic standpoint only. It was determined that adequate supplies of water may be obtained from mainstream low-flow (direct stream source), reservoir sources, and certain groundwater aquifers. Depending upon the geographical location of a CG plant complex, some or all of these alternative sources will be available. It is of interest, therefore, to gain some idea as to the relative cost of obtaining water from these, and to investigate the effect of such a cost upon the final supply price of synthetic gas.

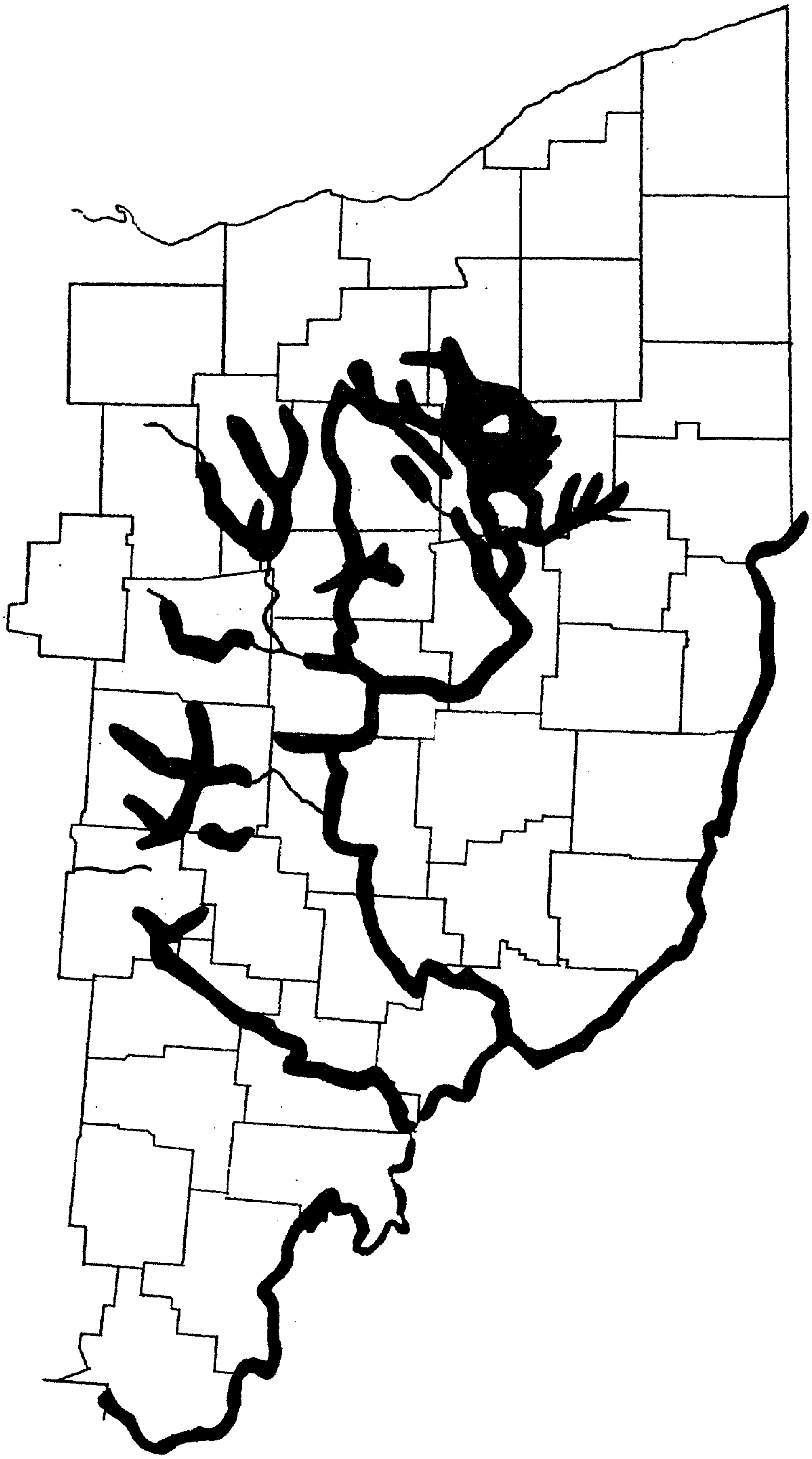


Figure 4-5. Major Groundwater Sources in Study Area.

River Valley Source	Thickness (feet)	Yields of high-capacity wells (gpm)	Well depths (feet)	Hardness (mg/l)	Iron (mg/l)	Total dissolved solids (mg/l)
Tuscarawas	20-150	100-2000	40-290	150-470	0.2-4.0	200-650
Walhonding	20-100	180-2100	35-180	150-320	0.1-2.0	180-450
Muskingum	20-150	100-1000	40-230	250-900	0.0-8.0	330-1000
Hocking	15-75	75-500	45-140	250-410	0.1-2.4	300-560
Upper Ohio (Pgh to Marietta)	10-40	100-1500	60-100	130-400	0.1-3.0	250-650
Ohio River (Marietta to Point Pleasant)	10-60	200-1500	55-100	130-300	-	220-460
Ohio River (Point Pleasant to Maysville)	60-100	100-500	60-80	70-210	0.1-3.0	150-500

Table 4-3. Groundwater Characteristics in Study Area
(Source: Deutsch, et al, 1969)

A cost comparison was made of the three alternative sources of water using data published by Bovet (1974). These data, in turn, are derived principally from a comprehensive study by Black and Veatch Consulting Engineers (1963). Trending was carried out based upon the Engineering News Record Building Cost Index of 1011 for January, 1972 and the base period value of 584 for January, 1963. An interest rate of 10 percent was chosen to reflect the cost of capital in the private sector. An economic life of 25 years was assumed for such items as pumps, water wells, and equipment, while 50 years was taken to be the economic life of reservoirs, pipelines and building structures. A planning horizon of 50 years was used. In all cases it was assumed that water transmission of 1 mile would at least be required to convey the water supply from source to plant. This cost thus enters as part of all alternative sources. Conveyance for greater distances would increase costs as derived below for any alternative source. Results of the economic comparison are shown in Table 4-4. Capital costs are defined to include the structural work for reservoirs, pipelines, pumping stations, well fields, and treatment plants, as well as the purchase of land, right-of-way, and equipment. Engineering, administration, and financing charges are also listed as capital costs. Operation and maintenance costs are generally subdivided into general O & M for a given structure or piece of equipment, and power O & M costs for pumping.

Water treatment is listed as a separate category for each source. Chemical costs vary depending upon the expected water quality of each source. A reservoir source has the lowest water treatment cost since, in general, it would be expected that such water is lower in turbidity than a direct stream source. The direct stream source has the next lowest water treatment cost. The cost of groundwater treatment is highest for the three alternatives. This is due to the general requirement in the study area of softening groundwater before it can be used for industrial coal gasification.

In comparing the total cost of a 25 MGD supply from the three sources, it is seen that direct surface water use is the least expensive at a present value cost of $15,207,000, with a reservoir source next at $23,013,000, and finally, ground-

Table 4-4. Generalized Cost Comparison of Alternative Water Supply Sources for Coal Gasification in Southeastern Ohio (25 MGD supply).

Cost Item	Direct Stream Source (PV, $)	Reservoir Source (PV, $)	Groundwater Source (PV, $)
1. Source Development			
A. Capital Cost:			
1) Construction	-	6,280,000	1,082,000
2) Engineering, Administrative, and Financing	-	652,000	108,000
3) Land	-	244,000	22,000
B. Operation and Maintenance:			
1) Structure	-	1,290,000	1,288,000
2) Pumping (exclusive of power)	-	-	1,565,000
3) Pumping (power)	-	-	2,210,000
Subtotal 1:	-	8,466,000	6,275,000
2. Water Transmission (1 mile)			
A. Capital Cost			
1) Pipeline and R.O.W	273,000	273,000	273,000
2) Pumping Station	989,000	989,000	989,000
3) Engineering, Administrative, and Financing	117,000	117,000	117,000
B. Operation and Maintenance:			
1) Pipeline	7,000	7,000	7,000
2) Pumping Station (exclusive of power)	1,336,000	1,336,000	1,336,000
3) Pumping Station (power)	629,000	629,000	629,000
Subtotal 2:	3,351,000	3,351,000	3,351,000

(Continued next page)

Cost Item	Direct Stream Source (PV, $)	Reservoir Source (PV, $)	Groundwater Source (PV, $)
3. Water Treatment*			
A. Capital Cost			
1) Plant Construction	4,070,000	4,070,000	4,070,000
2) Engineering, Administrative, and Financing	407,000	407,000	407,000
3) Land	81,000	81,000	81,000
B. Operation and Maintenance			
1) Plant (general)	4,240,000	4,240,000	4,240,000
2) Plant (chemicals)	3,320,000	1,660,000	5,520,000
3) Plant (power)	738,000	738,000	738,000
Subtotal 3:	12,856,000	11,196,000	15,056,000
Total:	16,207,000	23,013,000	24,682,000

*Does not include neutralization or softening of surface water sources water at a cost of $24,682,000. These costs are, respectively, 17.9, 25.4, and 27.2¢ per 1000 gallons. It should be noted, however, that both the direct stream and reservoir sources may incur the additional costs of neutralization and softening, if such sources are affected by acid mine drainage. The latter is a problem of real concern in Southeast Ohio today, and could become more severe with increased mining activity to supply coal gasification plants. The cost of neutralizing a 25 MGD source having an acidity of 400 mg/l can be calculated as $22,800,000 on a January, 1972, present value basis (Shumate, et al., 1974). This represents a cost of 25.1¢ per 1000 gallons, and far overshadows any other cost component. In addition, the neutralization process would undoubtedly necessitate a further treatment stage to remove hardness at an additional cost of 3.0¢ per 1000 gallons. If this were to be the case, a groundwater supply would be much more economical. The relative degree of acid mine drainage control in the study area is therefore very important from a water supply standpoint.

The relative impact of the cost of water supply on the price of synthetic natural gas can be determined using the above cost figures. At a consumptive water use of 25 MGD, each 10¢ per 1000 gallons cost increase for water supply would add 1.007¢/MCF to the price of gas. The range of the cost increase for the study area would therefore be from about 1.8¢/MCF for a direct stream source to 2.74¢/MCF for a groundwater source. At a gas price of $1.50/MCF, the cost of water would represent from 1.2 to 1.8 percent of the final price. This is not an insignificant portion of total costs, and efforts would be expected to determine the least cost source for a given geographical area, along with consideration of water conservation measures.

The above cost comparison has been conducted using generalized cost data, and under the assumption that each alternative source could supply all the needs of a CG plant. In any given geographical area, site characteristics for well fields, direct stream sources and reservoirs will determine actual costs. It is concluded, however, that none of the three alternative sources can be eliminated from consideration a priori in such a detailed cost analysis. Also, consideration should be given to the conjunctive use of the three sources, to take advantage of possible savings in treatment costs derived from the blending of supplies, and as a means of obtaining the necessary supply when shortages occur in any one source.

Chapter 5 - COAL GASIFICATION SITING MODELS

5.1 Introduction

Requirements for the proper siting of energy production facilities have increased considerably in the last decade. Criteria for proper siting have been expanded beyond the historical concerns for economy and efficiency to include environmental and social factors, as well as regional economic development. In addition, the range of technological alternatives has been greatly expanded. For example, in the electrical generation industry, nuclear fission plants are now competitive with fossil-fueled electric power plants in most geographical areas. Site selection studies incorporating these new criteria and technologies in the electric power industry are reported in the literature (Calvert and Heilman, 1972, Seiple, 1974, Perla, 1974).

Mathematical models with optimization characteristics can also be utilized to determine system component design and configuration. In the electric power industry, models of this type are exemplified by the works of Marks and Borenstein (1970), and Farrar and Woodruff (1973). Others are reviewed by Padalko (1973). Generally, these have been applied to solve a specific technological-environmental problem in a somewhat restricted geographical setting (for example, the problem of optimal fossil-fueled power plant siting under thermal discharge limitations). More recently, formulations have been developed to treat the energy system in a more comprehensive manner (Hoffman, 1973). Such models incorporate alternative energy sources (coal, gas, nuclear, hydropower, etc.), follow the complete supply chain (extraction, transportation, processing, distribution, etc.), and maintain fixed levels of environmental standards. The criterion of optimality in almost all of the above models has been that of economic efficiency in meeting fixed levels of demand. Descriptive energy flow models have also been developed, however, to test alternative National energy policies (Limaye and Sharko, 1973).

Since coal gasification has only recently been seen as a potential policy option, few energy models exist which incorporate this technology, and all of these fall into the category of descriptive (analytical) models for the testing of alternative energy policy options. A major purpose of this chapter is to develop an optimization model which treats the problem of coal gasification plant siting in a comprehensive manner. The model seeks the most economical set of plant locations to meet a specified array of gas consumption demands. The objective function incorporates plant costs, coal and gas transport costs, as well as the cost of solid waste disposal and water supply. Two models are developed, the first for optimal siting of high-Btu coal gasification plants, and a second for optimal siting and determination of the best combination of both low and high-Btu plants. Both models result in linear programming (LP) formulations which treat the siting problem at a given point in time (the year 1985, for example). It is shown how the proposed models could be extended to incorporate considerations of system expansion as a time-phased process.

5.2 LP Model 1: High-Btu Plants

The problem of siting coal gasification (CG) plants can be viewed in an economic sense as one of minimizing all direct costs incurred in the manufacture and supply of gas to the final consumer. The demand for synthetic gas from the industrial, commercial and residential sectors is assumed to be known for a given point in time (for example, the years 1985 and 2000). Direct costs to be considered herein are: 1) coal transport from mine sources to the CG plant complex, 2) gas transport from the CG plant complex to the final consumer, 3) solid waste disposal from the CG plant complex, and 4) the cost of water for the CG plant complex. It is assumed that actual plant costs for high-Btu gas production are invariant with location, and can therefore be omitted in the optimization program. If this is not the case, such costs can be included in the formulation to follow, with no significant increase in problem complexity. Viewed spatially, problem components can be defined as follows:

- I, the set of possible coal supply sources ($i = 1, 2, \ldots, m$);
- J, the set of potential sites for CG plant complexes ($j = 1, 2, \ldots, n$);
- K, the set of demand centers to be supplied with synthetic gas ($k = 1, 2, \ldots, p$);
- L, the set of possible solid waste disposal sites ($l = 1, 2, \ldots, m, m + 1, \ldots, s$); and
- R, the set of hydrologic regions for water supply ($r = 1, 2, \ldots, z$).

The following decision variables are defined (wherein superscript 1 refers to high-Btu CG plants):

C^1_{ij}, amount of coal shipped from coal deposit i to coal gasification complex j for use by high-Btu plants (tons/day);

G^1_{jk}, amount of high-Btu gas sent from CG plant complex j to demand center k (MMCF/day);

W^1_{jl}, amount of solid waste sent from high-Btu plants at CG complex j for disposal at mining or solid waste disposal site l (tons/day); and

Q^1_j, amount of water consumed in high-Btu CG plants in complex j (MGD).

The following data are defined to reflect the relevant costs in the problem:

c_{ij}, unit cost of shipping coal by most economical mode from coal deposit i to CG plant complex j (\$/ton mile);

d_{ij}, distance from coal deposit i to CG plant complex j (miles);

d_{jl}, distance from CG plant complex j to mining or solid waste disposal site l (miles);

g^1_{jk}, unit cost of transporting high-Btu gas from CG complex j to demand center k (\$/MMCF/day);

w_{jl}, unit cost of transporting solid waste from CG plant complex j to mining or solid waste disposal site l (\$/ton mile); and

q_j, unit cost of supplying water at CG plant complex j (\$/MGD).

With the above definitions, the linear programming objective function can be written as:

$$\text{minimize TC} = \sum_{i=1}^{m} \sum_{j=1}^{n} c_{ij}\, d_{ij}\, C^1_{ij} + \sum_{j=1}^{n} \sum_{k=1}^{p} g_{jk}\, G^1_{jk}$$

$$+ \sum_{j=1}^{n} \sum_{l=1}^{s} w_{jl}\, d_{jl}\, W^1_{jl} + \sum_{j=1}^{n} q_j\, Q^1_j \qquad (5\text{-}1)$$

where successive terms represent the total cost of coal supply, gas transport, solid waste disposal, and water supply, respectively. Although these are written in a form resembling only transport costs, it is obvious that the purchase price of coal can be included in its unit price term, and that on-site solid waste disposal costs can similarly be accounted for without changing the form of the objective function. Components of the water supply cost are also handled in this manner. In particular, care should be taken to include all opportunity costs involved in the consumptive use of water. For example, any increased costs of downstream wastewater treatment that may be necessitated, any loss of irrigation water supply, or other external loss that is directly or indirectly caused, should be accounted for in the assigned unit cost of water. It is also clear that in any given siting study, the existing transport network for coal and gas will have a very large impact on the determination of these unit costs.

Solid waste disposal sites must be selected to handle the considerable quantities of such wastes produced. Among the candidate sites for this purpose would be coal deposits actively mined for coal gasification. The present model permits the inclusion of such sites as well as others considered to be favorable for such use.

Constraints on the optimization can be written utilizing the following definitions:

N^1_j, number of high-Btu plants of 250 MMCF/day capacity at CG complex j;

v^1, amount of coal used by a high-Btu plant of 250 MMCF/day capacity (tons/day);

CS_i, raw coal supply available from coal deposit i (tons/day);

D_k, demand for gas of heating value equivalent to high-Btu gas at demand center k (MMCF/day):

w^1, fraction of coal used at a high-Btu CG plant that becomes solid waste;

e_i, fraction of coal removed from coal deposit i that can be replaced with solid waste;

WD_l, capacity of solid waste disposal site l (tons/day);

q^1, amount of water consumed by a high-Btu CG plant of 250 MMCF/day capacity (MGD);

QA_j, amount of water available (at cost q_j) at CG complex j (MGD); and

QA_r, amount of water available for coal gasification in hydrologic region r (MGD).

It is convenient to speak of the number of 250 MMCF/day, high-Btu plants existing at a plant site, rather than total synthetic gas output. The first constraint of the model is merely definitional to achieve this conversion. It is based upon the total amount of SNG being produced at the CG plant complex:

$$\sum_{k=1}^{p} G^1{}_{jk} = 250\ N^1{}_j \qquad (j = 1,\ 2,\ \ldots,\ n) \qquad (5\text{-}2)$$

The driving constraint of the model is that the demand at every demand center be met:

$$\sum_{j=1}^{n} G^1{}_{jk} = D_k \qquad (k = 1,\ 2,\ \ldots,\ p) \qquad (5\text{-}3)$$

Each CG complex must receive an amount of coal necessary for the production of SNG:

$$\sum_{i=1}^{m} C^1{}_{ij} = \frac{v^1}{250} \sum_{k=1}^{p} G^1{}_{jk} \qquad (j = 1,\ 2,\ \ldots,\ n) \qquad (5\text{-}4)$$

Coal shipments from every active supply site must not exceed the capacity of the mine or mines, when a specific production technology is known:

$$\sum_{j=1}^{n} C^1{}_{ij} \leq CS_i \qquad (i = 1,\ 2,\ \ldots,\ m) \qquad (5\text{-}5)$$

From each CG plant complex, solid waste must be disposed of. This is assured by writing:

$$w^1 \sum_{i=1}^{m} C^1{}_{ij} = \sum_{l=1}^{s} W^1{}_{jl} \qquad (j = 1,\ 2,\ \ldots,\ n) \qquad (5\text{-}6)$$

When active coal sources are utilized for solid waste disposal, adequate space must be available at all times:

$$\sum_{j=1}^{n} W^{1}_{ji} \leq \sum_{j=1}^{n} e_i C^{1}_{ij} \qquad (i = 1, 2, \ldots, m) \qquad (5\text{-}7)$$

A similar condition must be maintained at all designated solid waste disposal sites:

$$\sum_{j=1}^{n} W^{1}_{jl} \leq WD_l \qquad (l = m + 1, m + 2, \ldots, s) \qquad (5\text{-}8)$$

Available water supplies at individual CG plant complexes and in delineated hydrologic regions must not be exceeded:

$$q^1 N^1_j = Q^1_j \qquad (j = 1, 2, \ldots, n) \qquad (5\text{-}9)$$

$$Q^1_j \leq QA_j \qquad (j = 1, 2, \ldots, n) \qquad (5\text{-}10)$$

$$\sum_{j \epsilon r} Q^1_j \leq QA_r \qquad (r = 1, 2, \ldots, z) \qquad (5\text{-}11)$$

In addition, non-negativity conditions are imposed on all variables:

$$C^1_{ij}, N^1_j, G^1_{jk}, W^1_{jl}, Q^1_j \geq 0 \qquad (5\text{-}12)$$

The above model can be used to determine the sensitivity of high-Btu coal gasification plant location to changes in unit costs of coal supply and transport, gas transmission, solid waste disposal, and water supply. Similar sensitivity studies can be conducted upon the total quantities of coal and water available, or projected gas demands in different geographical areas. This is important since many times the availability of resources or projected consumer demands are known only within certain limits.

From the standpoint of water supply management, the dual variables associated with the water supply constraints (5-10, 5-11) are of great significance. These indicate the 'shadow prices', or true economic value of additional incremental supplies at a CG plant complex or in a hydrologic region. The question of whether interbasin transfers of water would be economically justified can be answered by comparing the real unit costs of such transfers to the value of the dual variables for water supplies in each basin.

Certain refinements can be made in the above model, if desired. In particular, system capacity expansion over time could be handled by the introduction of a period index, t, where a suitable length for the period might be five years. All decision variables would then have the additional subscript index, t, and certain coefficients in the above model would have to be modified accordingly. A present worth discount factor, λ_t, would also be applied to all costs incurred in time period t. Using such a modified program, the most economical capacity expansion of the SNG system could be determined at five-year increments for an arbitrary time duration, say 1985-2010. The time-staged program would accurately take account of the total availability of coal supplies and the capacity of solid waste disposal sites over time, since the cumulative use of such resources must be restricted at any one site.

Further refinement would be to insist that an integer number of standard, high-Btu plants be present at any potential CG complex. Assuming first economies, and then diseconomies of scale as CG plant size is increased, the literature value of 250 MMCF/day SNG output for a standard plant should represent the proper scale to achieve the lowest unit cost of production. A fractional value for the optimal number of plants to be located at any CG complex would therefore require a larger unit cost coefficient than is allowed for in the linear programming formulation. If this is considered to cause serious error, or if only standard sized plants are to be constructed, application of a branch-and-bound algorithm to the linear programming results would ensure integer solutions. If the incremental gas demand to be supplied by CG plants does not exactly require an integer total number of plants, some small amount of excess capacity will necessarily result from the application of the branch-and-bound technique, and an artificial demand would have to be created to accept the excess supply. If, in actuality, the extra SNG would not be produced, then the cost coefficient associated with this artificial demand in the LP formulation should be set equal to zero. Alternatively, if it were known that the excess supply could be sold, say, on the interstate market, this real demand with its associated transport cost could be added to the model. This consideration becomes even more important in the time-phased problem, since excess capacity at a given CG complex in one time period can be utilized in later periods, and the optimal sequence of such excesses is to be determined.

5.3 LP Model 2: Low and High-Btu Plants

Although most attention in the literature and at the National policy level has been given to the technology, siting requirements, and environmental effects of high-Btu coal gasification, the option of low-Btu gas production offers real advantages. The technology of low-Btu coal gasification exists today and has been commercially proven. It thus does not require the extensive process and materials development necessary for high-Btu plants, and producing plants could be on-line in only a few years as compared to about 10 years for high-Btu plants utilizing new process concepts. Conversion of some types of industrial plants to the use of low-Btu gas would release significant quantities of high-Btu gas for domestic and commercial uses. In this regard, such industries as iron and steel, glass, chemicals, and lime are large consumers of natural gas in the Ohio area. Low-Btu plants have been recommended for design and construction at some 50 industrial sites in Ohio (Colosimo, 1974).

Low-Btu plants are generally expected to be located on the same site as, or very near to, the industrial plant being served. This is the case since the transport cost of low-Btu gas is high on a per unit Btu basis. Potential site locations for low-Btu plants are allowed to be remote from industrial areas in the current model, however. This is done because in any given situation such factors as water availability, solid waste disposal costs, and relative transport cost of coal and gas may vary considerably, making more remote sites potentially advantageous.

Conversely, the option of placing high-Btu CG plants at or near market centers is also maintained.

In the formulation which follows, the terms C^h_{ij}, G^h_{jk}, W^h_{jl}, Q^h_j, N^h_j, g^h_{jk}, v^h, w^h, and q^h are as defined above, but now refer to either high-Btu (h=1) or low-Btu (h=2) plants of 250 MMCF/day capacity. In addition, define

c^h, present value of capital plus operation and maintenance cost of high (h = 1) and low-Btu (h =2) coal gasification plants of 250 MMCF/day capacity ($),

GD_k, maximum industrial demand for high-Btu gas at demand center k that could be replaced with low-Btu gas (MMCF/day).

The objective function then becomes

$$\text{minimize} \quad TC = \sum_{h=1}^{2} \sum_{j=1}^{n} c^h N^h_j$$

$$+ \sum_{h=1}^{2} \sum_{i=1}^{m} \sum_{j=1}^{n} c_{ij}\, d_{ij}\, C^h_{ij} + \sum_{h=1}^{2} \sum_{j=1}^{n} \sum_{k=1}^{p} g_{jk}\, G^h_{jk}$$

$$+ \sum_{h=1}^{2} \sum_{j=1}^{n} \sum_{l=1}^{s} w_{jl}\, d_{jl}\, W^h_{jl} + \sum_{h=1}^{2} \sum_{j=1}^{n} q_j\, Q^h_j \qquad (5\text{-}13)$$

where respective terms refer to the cost of plant, coal supply and transport, gas transport, solid waste disposal, and water supply for both high and low-Btu CG plants.

Constraints are similar to those of the first formulation but must reflect the option of low-Btu plants. These are

1) definitional constraints on the number of plants;

$$\sum_{k=1}^{p} G^h_{jk} = 250\, N^h_j \qquad (j = 1,\ 2,\ \dots,\ n),\ (h = 1,\ 2) \qquad (5\text{-}14)$$

2) constraints that demand be met;

$$\sum_{j=1}^{n} G^{1}_{jk} + \frac{200}{950} \sum_{j=1}^{n} G^{2}_{jk} = D_k \qquad (k = 1, 2, \ldots, p) \qquad (5\text{-}15)$$

3) constraints on the maximum amount of low-Btu gas to be supplied;

$$\sum_{j=1}^{n} G^{2}_{jk} \leq \frac{950}{200} GD_k \qquad (k = 1, 2, \ldots, p) \qquad (5\text{-}16)$$

4) constraints on coal received;

$$\sum_{i=1}^{m} C^{h}_{ij} = \frac{v^h}{250} \sum_{k=1}^{p} G^{h}_{jk} \qquad (j = 1, 2, \ldots, n), \ (h = 1, 2) \qquad (5\text{-}17)$$

5) constraints on coal supplied;

$$\sum_{h=1}^{2} \sum_{j=1}^{n} C^{h}_{ij} \leq CS_i \qquad (i = 1, 2, \ldots, m) \qquad (5\text{-}18)$$

6) constraints on solid waste disposal;

$$\sum_{i=1}^{m} w^h C^{h}_{ij} = \sum_{l=1}^{s} W^{h}_{jl} \qquad (j = 1, 2, \ldots, n), \ (h = 1, 2) \qquad (5\text{-}19)$$

7) constraints on solid waste disposal at active mines;

$$\sum_{h=1}^{2} \sum_{j=1}^{n} W^{h}_{ji} \leq \sum_{h=1}^{2} \sum_{j=1}^{n} e_i C^{h}_{ij} \qquad (i = 1, 2, \ldots, m) \qquad (5\text{-}20)$$

8) constraints on solid waste disposal at disposal sites;

$$\sum_{h=1}^{2} \sum_{j=1}^{n} W^{h}_{jl} \leq WD_l \qquad (l = m + 1, m + 2, \ldots, s) \qquad (5\text{-}21)$$

9) constraints defining water use;

$$q^h N^{h}_{j} = Q^{h}_{j} \qquad (j = 1, 2, \ldots, n), \ (h = 1, 2) \qquad (5\text{-}22)$$

10) constraints on water availability at CG complexes;

$$\sum_{h=1}^{2} Q^h_j \leq QA_j \qquad (j = 1, 2, \ldots, n) \qquad (5\text{-}23)$$

11) constraints on water availability by hydrologic region;

$$\sum_{h=1}^{2} \sum_{j \in r} Q^h_j \leq QA_r \qquad (r = 1, 2, \ldots, z) \qquad (5\text{-}24)$$

Finally, non-negativity must be imposed on all variables; C^h_{ij}, N^h_j, G^h_{jk}, W^h_{jl}, and Q^h_j.

As opposed to LP Model 1, the above formulation takes into account trade-offs involved between construction of low and high-Btu CG plants. The model could be used to test the sensitivity of high-Btu plant locations to changes in service demand caused by alternative patterns of low-Btu plant construction for industry, or to any other change in problem parameters, such as cost coefficients, total consumer demand or water availability.

An assumption of the model is that high or low-Btu plants can be located at any of the possible CG complexes. If this is not the case, terms in the above formulation which represent non-permissible options would be removed. Also, it should be mentioned that if low-Btu plants of a size larger or smaller than 250 MMCF/day capacity are desired, a scaling factor could be applied to certain terms of the above formulation to reflect this condition without significantly changing the problem.

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